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BASIC SYSTEM DESCRIPTION FOR COAL GAS/FUEL  
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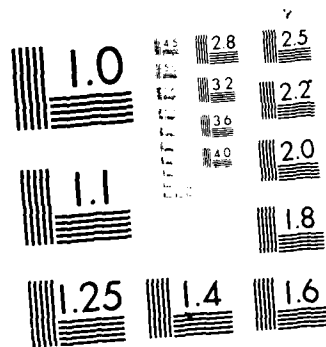
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# BASIC SYSTEM DESCRIPTION

FOR

COAL GAS / FUEL CELL / COGENERATION PROJECT

REPORT CLIN 0001

PREPARED FOR

DEPARTMENT OF THE ARMY  
AND  
GEORGETOWN UNIVERSITY

JANUARY, 1985

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ARMY R&D PROGRAM FOR  
COAL GAS/FUEL CELL/COGENERATION

1.0 Introduction

1.1 General

This facilities planning project is the first major step in a demonstration program developed and proposed by Georgetown University and Ebasco Services Incorporated to install coal gas/fuel cell/cogeneration (GFC) systems to service Department of Army (DOA) sites.

The objective is to perform analysis of four sites to determine if the system will lead to increases in energy efficiency, higher conservation standards, and economic benefits sufficient to attract third-party equity investment to offset a significant portion of the funds required from the DOA. This objective is reflected in the language of the Congressional Department of Defense Appropriations Bill, 1984:

ENERGY CONSERVATION TECHNOLOGY

The Committee requests the Army to reprogram \$820,000 within available funds to implement an interagency agreement with the Department of Energy and Georgetown University to study whether fuel cell technology could be combined with a coal gasification cogeneration program at specific sites where coal conversion potential exists. Sponsors of the proposal have identified sites in Texas, Pennsylvania, Alaska and the District of Columbia as candidates for such review. The committee believes such technology is worth pursuing, should it lead to increases in energy efficiency and higher conservation standards. The Committee recognizes that this effort is subject to authorization.

Therefore, to satisfy the objectives of this facilities planning study, it will be necessary to determine demonstration plant costs, operating characteristics, economic and financing viability, third-party participation interest, and eventual commercial plant operating and economic benefits. These determinations will be accomplished by performing the following tasks.

- I                      FACILITIES PLAN: Systems description, conceptual design and arrangements, plant cost estimates, life cycle costs and project plan.
- II                     ECONOMIC-FINANCIAL ASSESSMENT: Detailed cash flow and return on total investment (without regard to tax benefits), benefits analysis for army sites, risks.
- III                    OWNERSHIP AND FINANCE ASSESSMENT: Determine specific feasible financing structures for different ownership business arrangements, tax benefits, risk and sensitivity analyses.

## 1.2 Basic System Description

This report covers the first (Item 0001) of nine deliverables included in Task I, defining the basic system description. The description addresses the United Technologies Corporation and Westinghouse fuel cell technologies, coal gasifiers and characterizes basic design and performance parameters. Technical risks have been identified in certain areas of the system and approaches to minimize these risks are discussed. The relative importance of various system features have been defined. Design and performance characteristics have been classified as common to all sites or site specific. Any documents which are referenced from previous studies in the description are included in the Appendix.

Following this submittal will be separate reports on four sites: Washington, DC, Pennsylvania, Texas and Alaska. These reports will determine existing conditions as they would affect installation of a coal gas/fuel cell/cogeneration (GFC) facility, including current and future energy requirements, local economics and any site characteristics that would affect the feasibility of this installation.

A second series of reports will for each site, present a specific description of the facility, including energy balances, energy use analysis, equipment lists, process flow diagrams, general arrangement drawings, technical study results and a project implementation schedule.

Additional reports covering the remaining items described in Tasks II and III will then follow.

## 2.0 OVERALL PLANT DESCRIPTION

### 2.1 General

The gasification/fuel cell/cogeneration (GFC), system provides a means of producing electricity and useful heat efficiently and with minimal environmental effects from coal, our most abundant fuel, nationally. Fuel cells are a near-commercial technology and have many features that make them attractive for power plants.

This section describes the overall system for a coal gasification fuel cell plant. This base system design will be adapted to four specific sites with modifications as required to satisfy local conditions. The site specific designs are to be described in subsequent reports.

Two of the systems are based on the UTC fuel cell and located in Washington, DC and in Fort Hood, Texas; the remaining two are based on the Westinghouse fuel cell and located in Scranton Pennsylvania and Anchorage, Alaska. The Washington, DC GFC is considered as the base design from which the necessary design adjustments are made to suit conditions at the other three sites. Performance characteristics for the base design plant are given in Table 2-1. Overall criteria for all sites are as follows:

- a base load fuel cell plant using gasified coal
- base design to be adapted to four specific sites
- plant sized for either one 11.6 MWe United Technologies fuel cell with or one 7.5 MWe Westinghouse fuel cell, depending on site
- all equipment to be commercially proven except the fuel cell and inverter
- atmospheric air blown gasifier to be used
- design to include cogeneration
- ownership by private party
- plant configured to maximize revenue of the user
- plant components truck transportable
- short procurement and construction time (2 years)

- meet all federal and local emission standards
- minimize land and water usage
- aesthetics and environmental factor to allow location in an urban area
- design life 25 years.

With the exception of the Anchorage GFC, system, all systems use coal or lignite as the primary fuel with natural gas as the secondary or backup source. Because of currently low gas prices in Anchorage, natural gas is the primary fuel for that site with coal as the backup. Some amount of processing is required to prepare the natural gas for fuel cell use.

## 2.2 Plant Description

It is estimated from previous studies (Reference 2-1) that approximately two level acres will be sufficient to contain the system. However, the site at Washington DC will be divided into two parcels: one for the coal gasification and gas processing and the other for the fuel cell and thermal management system. The tallest structure at all sites is expected to be the Wellman-Galusha gasifier which, including the bucket elevator, is 85'-0" above the base slab.

The systems based on the UTC and Westinghouse cells will have nominal gross electrical outputs of 11.6 MW and 7.5 MW respectively. Systems are studied as self contained modules though it is evident that economics of scale may be possible with a single gas processing section sized to feed gas to multiple fuel cell modules.

Cogenerated steam available for export is expected to be approximately 19,000 lb/hr for the UTC cell. Steam may, through the addition of a heat exchanger and circulating water pumps, be converted to hot water if required by the end user.

The values of net available power and net available heat in Table 2-1 will vary according to the fuel cell type, coal properties, site conditions such as elevation and temperature and according to the design options that are exercised.

TABLE 2-1

BASE SYSTEM PERFORMANCE  
(UTC CELL, WASHINGTON, D.C.)

Coal Input to Gasifier <sup>(1)</sup> , Tons/D	151
Heating Value of Coal Input <sup>(2)</sup> , Btu/hr	$163.6 \times 10^6$
Fuel Cell Output, MWe DC	11.6
Power Conditioner Output, MWe AC	11.0
Power From Gas Turbine, MWe	2.5
Auxiliary Power, MWe	3.1
Net Power, MWe	10.4
Export Steam @ 90 psia, lb/hr	19,000
Tar and Oils Heat Content, Btu/hr	$36.0 \times 10^6$
Heat Rate, Btu/Kwh	15,730
Heat Rate, Btu/Kwh <sup>(3)</sup>	10,320
Overall Plant Efficiency, %	56

Notes:

1. Based on maximum of 15% fines in as-received coal.
2. Based on higher heating value of 13000 Btu/lb
3. Takes credit for thermal value of export steam and gas process byproducts

A conceptual view of the base system design is given by the block flow diagram of Figure 2-1. The process starts with truck delivery of coal to the coal handling system which feeds screened coal to the gasifier. With the addition of combustion air, the gasifier produces hot raw gas and ash. The raw gas is cooled to condense and separate oils and tars and then compressed.

The base design for the Washington DC site includes motor driven centrifugal gas compressors which are electrically powered from the fuel cell. However for the remaining three sites, the option for direct drive of these gas compressors from the fuel cell combustor/expander will be considered.

Utilizing steam at 190 psia from the Thermal Management System, the gas undergoes a CO shift to reaction increase the hydrogen content. The gas is then desulfurized and heated before final polishing and feeding to the fuel cell.

Receiving compressed fuel gas and air at the anode and cathode respectively, the fuel cell electrochemically converts the energy in the hydrogen and oxygen components of these feed gases to DC power and heat.

The fuel cell power output is then conditioned for use in an AC utility network. Vent gases from the fuel cell power a combustor/expander which drives the air compressors. Optionally these air compressors can be motor driven permitting a greater amount of heat to be cogenerated due to hotter combustor gases entering the Heat Recovery Steam Generator (HRSG).

This latter equipment is part of the Thermal Management System which receives and "manages" heat from the fuel cell electrochemical reaction, from the combustor/expander and from any process heat source or process byproduct fuel such as tars and oils.

The design of the Thermal Management System largely determines the magnitude of the relative proportions of plant power output and export heat which are selected to best meet site requirements.



For example, heat received by the Thermal Management System can be used to drive a turbine generator or as in the base system design, used at a higher energy level to maximize export heat.

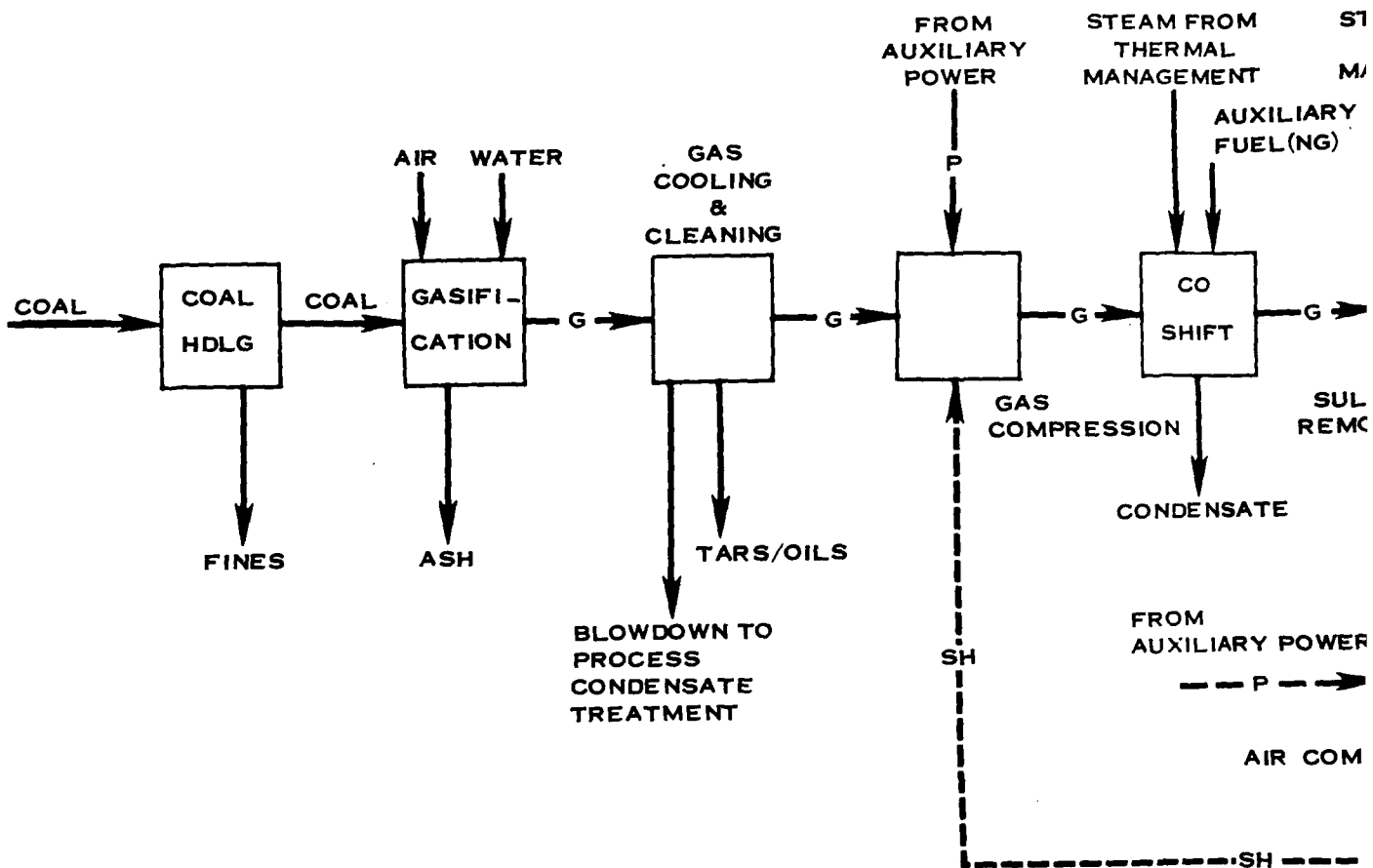
Also included in the TMS is a cooling water system that removes heat rejected from the gas process, from compressor intercoolers and from steam condensers serving power turbines.

Unlike the UTC fuel cell, the Westinghouse fuel cell is air cooled, and an air to water heat exchanger is interposed between the fuel cell and the steam system that limits the available steam pressure from this source to a value that is below the requirement by the CO shift. For this reason, differences in the Thermal Management Systems that support the UTC and Westinghouse fuel cells are to be expected as the study proceeds.

Other systems required to support the facility and which will be developed on a site specific basis, include instrumentation and controls, makeup water treatment, drainage, heating and ventilation of enclosures, freeze protection of equipment and piping, flush water and compressed air for maintenance.

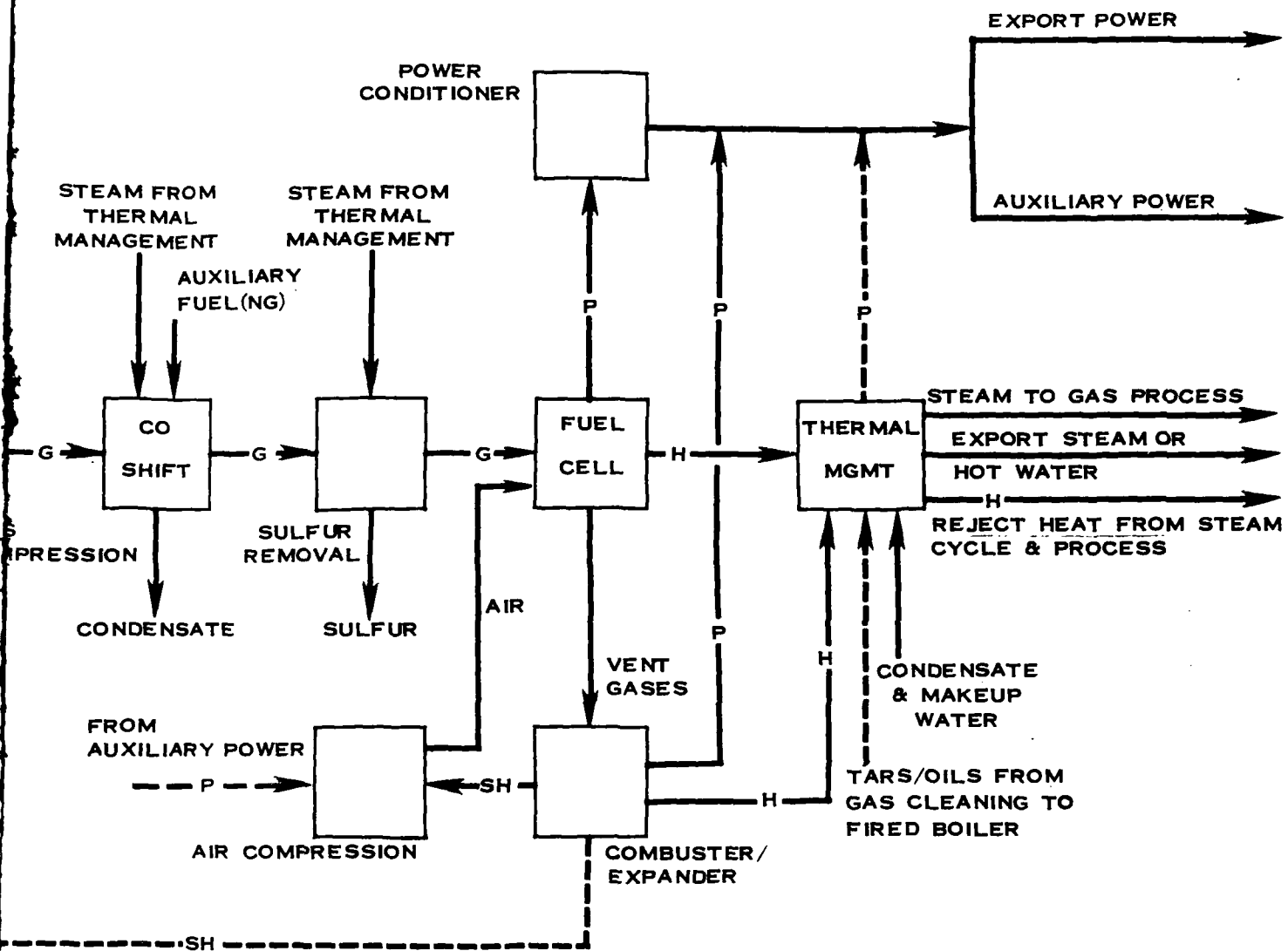
## 2.1 Reference

- 2-1 Kinetics Technology International Corp., "Assessment of a Coal Gasification Fuel Cell System for Utility Application", EPRI-2387, May, 1982.



**SYMBOLS:**

- OPTIONAL ---
- SH — SHAFT CONNECTION
- P — POWER
- H — HEAT
- G — FUEL GAS



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COAL GAS / FUEL CELL / COGENERATION

BLOCK FLOW DIAGRAM

FIGURE 2-1

EBASCO SERVICES INCORPORATED

### 3.0 COAL AND ASH HANDLING

#### 3.1 Coal Handling

The coal handling and storage system arrangement is shown in Figure 3-1.

Sized 1-1/4" x 1/4" stoker coal is delivered to the site in 20 ton trucks. The trucks discharge into an inground hopper. A typical delivery schedule would be 5 to 10 trucks per day.

The coal is transferred by screw feeder SF-1 to bucket elevator BE-1 which raises the coal to the top of two circular concrete silos. The coal is discharged to the center of the silos by means of continuous flight conveyor, FC-1.

Coal is reclaimed from the silos by means of screw feeders SF-2 and SF-3 and discharge into continuous flight conveyor FC-2. Flight conveyor FC-2 raises the reclaimed coal to a hooded screen. Fines less than 1/4" size are collected in the screen hopper.

Coal 1/4" size and over is discharged from the screen into bucket elevator BE-2 which discharges into continuous flight conveyor FC-3.

Flight conveyor FC-3 discharges the coal at the center of each gasifier storage hopper.

Fines collected in the screen hopper are discharged into an enclosed truck.

Each of two silos at the Washington, DC site would be sized for five days storage with resulting sizes and capacities are as follows:

<u>Site</u>	<u>Silo Dia.</u> <u>Ft.</u>	<u>Silo Height</u>	<u>Tonnage Capacity</u> <u>Based on 50 lb/ft<sup>3</sup></u>	<u>Volumetric</u>
		<u>From Top of Silo</u> <u>To Discharge</u>		<u>Capacity</u> <u>Ft<sup>3</sup></u>
Washington, DC	30	77	755	30,200

Because of poor flowability of lignite which can impede silo reclaim, enclosed pile storage should be considered for sites utilizing this fuel.

### 3.2 Ash Handling

Ash and dust produced through the gasification of coal will be collected and stored in bins and hoppers integral to the gasifier. Ash will also be collected and stored in the conical section of a mechanical cyclone.

The storage hoppers will be sized to store an equivalent material production of 24 hours. Capacity storage of hoppers for sites fueled with lignite will be increased to account for the higher ash content.

Ash and dust will be manually unloaded from their respective hoppers on a daily basis and loaded into a covered dump truck for off-site disposal. A dust suppression system consisting of a spray header with nozzles dispensing a chemical wetting agent will be installed at the discharge of the dust line. The ash pit outlet does not require a spray system since the material will be flushed with water for discharge.

Should the ash mineral analysis indicate a high percentage of  $\text{CaO}$  present in conjunction with a high percentage of  $\text{SiO}_2$ , the amount of water and quench retention time will be reduced to prevent binding of the ash in the ash pit.

According to prevailing winter temperatures, design of truck loading will include provisions for insulated siding and space heaters.

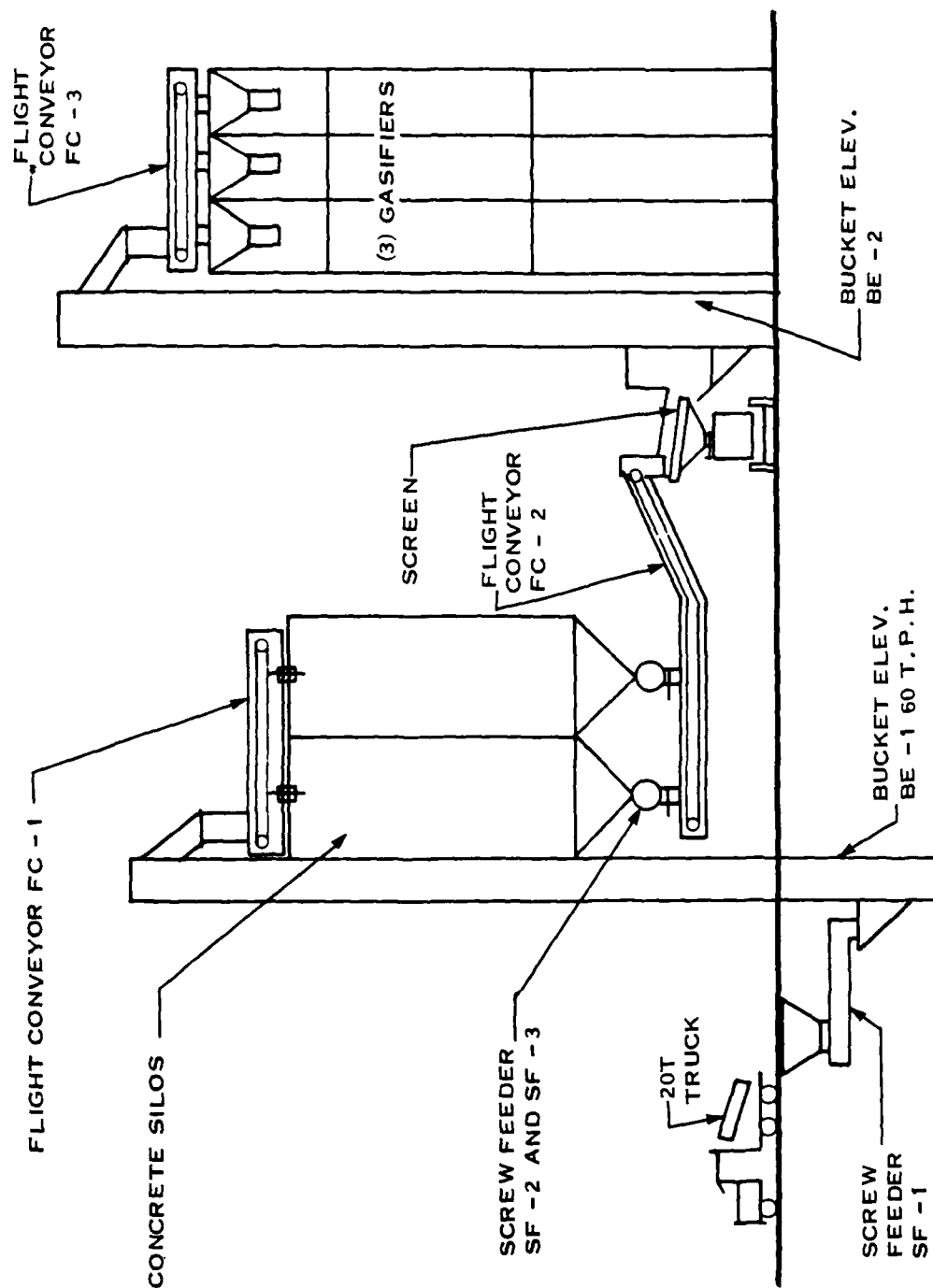


FIGURE 3 - 1 COAL HANDLING AND STORAGE SYSTEM - WASHINGTON D.C.

## 4.0 COAL GASIFICATION

### 4.1 Background

Gasification, the conversion of coal to a clean and convenient gaseous fuel, has been practiced for over 150 years on a world-wide basis. This practice continued up to the early part of the twentieth century when coal was the chief source of energy throughout the world. Through the years coal was supplanted first by oil, and then by natural gas in the United States. This change has taken place because of the availability of low cost oil and gas, the ease of firing oil and gas, and because of the clean nature of these fuels. The oil embargo of 1973, and the resultant high prices of oil resulted in consideration of alternate sources of energy, with particular attention being given to coal because of its great reserves. The drive for alternate energy sources reintroduced consideration of coal gasification in more advanced forms of the old technology. The evaluation and implementation of these technologies and other more advanced technologies have been slowed in recent years because of the reduction in oil prices, but coal gasification still offers a means of utilizing our vast coal reserves in an efficient and environmentally sound manner.

### 4.2 Gasifier Evaluation

This section is concerned with a review of available gasifiers and identification of the technology which is to be the basis of the study to analyze the benefits of installing a coal gasification/fuel cell system at four sites. The gasification systems considered fall into two categories: commercialized technologies and second generation technologies.

#### 4.2.1 Commercialized Technologies

Gasification systems that have been constructed in sizes able to process significant quantities to coal, and that have operated in a continuous mode to produce gas for a commercial application are considered to be commercialized technologies. The significance of this designation is that these technologies can be expected to be utilized with a minimum

of technical and commercial risk because of their demonstrated performance.

There are six commercialized gasification technologies that were considered. Key characteristics for each of these technologies are listed on Table 4-1.

The commercialized technologies can be divided into three major gasification types: fixed bed (also known as moving bed), fluidized bed, and entrained solids gasifiers.

#### 4.2.1.1 Fixed (Moving) Bed Gasifiers

In the moving bed gasifier, coal and flux, if necessary, are introduced at the top of the reactor, and move slowly downward, counter-current to ascending gas produced from the reactions with air or oxygen and steam which are introduced at the bottom. The counter-current movement of coal and oxygen/air is generally considered as ideal for reactor design. The ash content of the coal is removed from the bottom of the reactor. All of the commercialized moving bed gasifiers are of the dry ash type, meaning that the ash fusion temperature is not exceeded. Steam is added to the air or oxygen in order to keep the combustion temperature below that of ash fusion.

Highly swelling coals present a problem for fixed bed gasifiers because of their caking tendencies, but many caking coals can be handled by use of a mechanical stirrer or agitator.

Fixed bed gasifiers are limited in the percentage of the coal feed that can be in the form of fines. Fines are generally described as coal sizes less than 1/4 inch and they are usually limited to 15% of the total feed. For reasons of economy consideration must be given to briquetting excess fines for feed to the gasifier.

The Lurgi Dry Ash, the Wellman-Galusha, the Woodall-Duckham and the Stoic gasifiers are of the fixed bed type.



#### 4.2.1.2 Fluidized Bed Gasifiers

In the fluidized bed gasifier crushed coal (1/4" x 0) is introduced into a fluidized bed of partially gasified coal particles suspended in a flow of gas. Steam and air or oxygen are introduced at the bottom. Ash is removed from the bottom, and a particulate laden gas leaves at the top. The fluidized bed has a very uniform temperature. This temperature is high enough to ensure destruction of tars, but must not exceed the ash fusion temperature. Because of the screw feeder used for introduction of fresh coal into fluidized bed gasifiers the free swelling index (FSI) is usually limited to 2.5. Coals with a higher FSI require pretreatment. The Winkler gasifier is of the non-agglomerating, fluidized bed type. In this type the use of highly agglomerating coals can result in lower carbon conversion efficiencies.

#### 4.2.1.3 Entrained Solids Gasifiers

In entrained solids gasifiers pulverized coals and air or oxygen are introduced together and flow co-currently through the reactor. In the Koppers Totzek gasifier the reactants are introduced through horizontal opposed heads and flow upward reacting completely before exiting at the top. These gasifiers operate at temperatures above the ash fusion temperature. The molten ash combines into larger particles which drop to the bottom.

#### 4.2.2 Second Generation Technologies

This category includes gasification technologies which although not yet commercialized, meet certain conditions which give promise of commercialization in the foreseeable future. They are considered here because they may be commercially available for selection if this program proceeds to the implementation stages.

- o Generally, these technologies have advantages over the commercialized technologies because of larger capacities, higher operating pressure, better thermal efficiencies and/or improved environmental factors.

- o All of the gasifiers in this category have had successful pilot plant operation. Some have semi-commercial scale plants in operation.
- o Finally, although not yet fully commercialized these technologies either have definite plans or have advanced to semi-commercialized or demonstration status. The British Gas/Slagging Lurgi, KGN, Texaco and the U-Gas gasifiers are included in this category. A summary of characteristics for the Second Generation Gasifiers is given in Table 4-2.

The British Gas/Slagging Lurgi Gasifiers is a slagging version of the fixed bed Lurgi gasifier. Slagging conditions are achieved by reducing the steam fed with the air or oxygen thus increasing the temperature at the bottom of the gasifier. The slag is removed from the bottom of the unit into a lockhopper.

The KGN gasifier is a two-staged, dry-ash fixed bed gasifier. The performance is similar to the Lurgi gasifier except that the gas from the upper part of the gasifier, the distillation and drying zone, is recycled via a center pipe to the combustion zone at the bottom of the gasifier using a steam injection pump for the motive force. Only gas produced in the lower portion of the gasifier, free of tars and oils, is removed as product.

The Texaco gasifier is an entrained solids gasifier in which the coal is fed as a water slurry at the top of the gasifier together with air or oxygen. Flow is downward, and gasification occurs at the high temperatures generated. The manner of removing the ash as a slag depends on the cooling technique. If a quench gasifier is used the ash is quenched by dropping into a water bath at the bottom of the gasifier where it is removed to lockhoppers. An alternative is to position a radiant boiler below the gasifier cooling the gas and ash, and causing the ash to drop out at the bottom of the boiler.

The U-Gas gasifier is of the fluidized bed type with air or oxygen introduced at the bottom of the gasifier through a sloping distributor

grid and an ash removal device. Coal is pneumatically fed from lock hoppers into the lower part of the fluidized bed. The air/oxygen fed through the ash removal device results in a high overall carbon utilization. The U-Gas gasifier differs from the Winkler gasifier because it operates as an agglomerating gasifier. A high-temperature, vertical cylindrical zone in the center of the gasifier results in agglomeration of the ash into roughly spherical particles which drop down as they grow in size. They are removed through the ash removal device into a water-filled ash lockhopper.

#### 4.2.3 Gasifier Selection

In selecting a gasifier it was decided to use a commercialized gasification technology so that this study can benefit from the information derived from the demonstrated performance of these gasifiers.

The market direction of three of the commercialized gasifiers has been for larger sized units capable of treating 400 to 1300 short tons per day of coal. The capacities of the Lurgi Dry Ash, the Koppers-Totzek and the Winkler gasifiers are too large for the fuel gas requirements of a single cell of either the United Technologies or Westinghouse fuel cells, as is being considered for this study. Therefore, none of these gasifiers will be used as the basis for this study.

The remaining three commercialized gasifiers are all marketed with capacities compatible with the single fuel cell requirement. All three gasifiers, the Wellman Galusha, Woodall-Duckham and the Stoic are similar in operation and products. The Wellman Galusha gasifier is able to process coal with a wider range of free swelling index. For this reason and because of the availability of more technical and economic data, the Wellman-Galusha gasifier was selected as the basis for this study. This selection will be re-evaluated for each site in later stages of the program. The performance and economics of the Wellman-Galusha gasifier can be considered typical at this level of study.

### 4.3 Description of Gasification System

#### 4.3.1 Design Criteria

The Wellman-Galusha gasification system together with the Gas Processing System will be designed to meet the fuel gas requirements of the fuel cell. The coal design criteria for each of the proposed sites are listed on Table 4-3 through 4-6. The feed coal requirements will be based on producing sufficient fuel gas the United Technologies fuel all at the Washington, D.C. and Fort Hood, Texas sites, and sufficient fuel gas for the Westinghouse fuel cell at the Anchorage, Alaska, and Scranton, Pennsylvania sites.

#### 4.3.2 Description of Operations

The process flow diagram for the gasification system is shown on Figure 4-1. Coal is delivered to a Hopper/Feeder by the coal handling system. A bucket elevator delivers the coal to the feed bin and the feed mechanism.

##### 4.3.2.1 Feed Mechanism (See Figure 4-2)

In the Wellman-Galusha gas producer plant an open coal bunker is the uppermost part of the gasifier. The gasifier also has a lower, gas tight coal bin, under which is the gasifier reactor vessel having an ash cone at the bottom.

The upper bunker or bin is filled by the bucket elevator and discharges coal by gravity into the lower bin during refueling. The lower fuel bin, or "lock hopper" has interlocking gas tight valves top and bottom configured such that the bottom valves close before the top valves open, and vice versa. The valves are actuated by a coal valve drive motor located under the bin. To fill the lower bin the bottom valves are closed, and the upper valves opened, allowing coal to flow by gravity into the lock hopper. When the lock hopper is filled, usually in a matter of a few minutes, the valves are cycled, closing a upper valves and opening those at the bottom.

The lower fuel valves are kept open, except for refueling, to assure a continuous supply of fuel into the gasifier reactor vessel.

#### 4.3.2 Reaction Section (See Figure 4-3)

The gasifier is a double wall cylindrical vessel, with an inner shell of one inch thick steel. The inner shell is completely surrounded by a water jacket, and requires no refractory lining. The elimination of the brick or refractory lining eliminates not only the expense of the refractory material, but also drastically reduces maintenance expense, caused by ash fusing to the refractory.

The water jacket surrounds the sides of the inner shell and extends over the top. About four inches above the top of the inner wall there is an overflow pipe which prevents the water from completely filling the space between the inner and outer shell at the top of the vessel. Cooling water is introduced into the water jacket at the top of the vessel, and flows out through the overflow. The flow of water is controlled to keep the temperature of the water at a predetermined set point which corresponds to a desired air saturation (see paragraph 4.3.2.3).

Coal flowing down through the coal feed pipes enters the top of the gasifier and is contacted by the upward flow of hot gas generated in the gasifier reactor. The heat from the countercurrent flow of hot gas first evaporates moisture, then drives off volatiles from the incoming coal. The moisture and volatile matter becomes part of the outward bound gas stream. The dry, devolatilized coal char continues its slow downward flow through the gasifier, at a rate which is determined by the air flow into the unit which, in turn, sets the gasification rate. The coal char passes through two stages. The first stage consists of a reducing zone, where carbon dioxide produced from char which is burning below is reduced to carbon monoxide. Water vapor added to the incoming air is also reduced in this zone by the hot carbon in the char, producing hydrogen and additional carbon monoxide. The heat which supports this endothermic reaction is produced by the first zone directly below, wherein the carbon in the char is burned to form carbon dioxide in the familiar oxidation reaction. Air, saturated with water vapor, is introduced under this fire zone, and sustains combustion.

#### 4.3.2.3 Air System

The air blast which sustains combustion is generated by an external blower and, after passing over the water in the top of the water jacket, enters the gasifier vessel below the grate plates, flowing upward through the ash bed.

If air alone were used for combustion, the temperature of the fire zone would exceed the fusion temperature of the ash, and molten ash would fuse as it cooled, forming glassy solids (clinkers) in the ash bed.

To prevent the formation of clinkers and to provide a valuable fuel constituent, moisture is added to the blast air. This moisture moderates the fire bed temperature, and the water vapor thus introduced is reduced by the hot carbon above the first zone to produce hydrogen and carbon monoxide as previously described. In the Wellman-Galusha gasifier, moisture is added to the blast air by introducing the incoming air stream at the top of water jacket. Air blowing over the surface of the hot water in the top of the vessel absorbs moisture, and the saturated air is then piped to the gasifier under the grate. The amount of moisture in the blast air is a function of the temperature in the water jacket, which, in turn, is controlled by the rate at which cooling water is introduced into the jacket.

#### 4.3.2.4 Ash Removal

The burning coal in the fire zone rests upon a bed of ash produced by the combustion of the coal char, and this bed of ash in turn is supported by a slowly revolving set of eccentric grates. The grate speed is set to remove ash at the same rate it is produced, thereby keeping the depth of the ash bed and the location of the fire zone constant.

Ash removed from the gasifier vessel by the revolving grate drops into an ash cone at the bottom of the vessel. From there it is flushed out periodically with water into a truck or front end loader. Flushing the ash is of a few minutes duration and does not interfere with the normal operation of the gasifier.

#### 4.3.2.5 Particulate Removal

The hot gas produced in the gasifier contains some particulate, some moisture, and, if bituminous or lower ranked coals are gasified, volatile matter, principally aerosol tar and oil. The hot gas flows through a tangential entry dust cyclone, wherein dust particles drop out and settle in the cyclone cone. The hot gas then flows directly to gas cleaning equipment.

The particulates separated from the gas are stored in the cyclone cone, and are flushed out into a truck simultaneously with the wet ash from the gasifier in order to minimize dust problems.

#### 4.3.3 Flexibility of Operation

The Wellman-Galusha gasifier has converted into gas as high as 99 pounds of coal per square foot of grate area per hour. Also in commercial operation it has processed as little as 7.5 pounds of coal per square foot of grate area per hour. This corresponds to a range of operation of approximately from 10 percent to 110 percent of normal capacity. It is therefore not normally necessary to waste gas by venting to atmosphere when the demand for gas is small. However, a flare is provided, with its burner 10 feet above the top of the structure, capable of oxidizing the product gas in event of a short-term shutdown of the purification system. The gasifier is usually started with one load of coke before introducing the design coal.

The Wellman-Galusha gasifier can accept changes in coal quality without mechanical adjustment.

#### 4.3.4 Site Specific Characteristics

The principal site specific characteristics affecting the design of the gasification system is the coal type available as feed for each site. The coal type and the fuel cell to be used dictate the quantity of coal which must be gasified, and therefore, the number of coal gasification modules which will be required at each site.

A module consists of the bucket elevator, coal storage bins, a 10 foot single stage gasifier, cyclone, an air blower and the gasification structure. One gasification module requires an area of approximately 17 feet by 34 feet. The structure will be a little over 80 feet high.

It is estimated that three modules, each operating at 67% of normal capacity, will be required for the base case design at Washington, D.C. These will be located side by side so that the overall area requirement will be approximately 34 feet by 50 feet.

The steam requirements for gasification are met by the steam generated in the gasifier water jacket for all cases except for those sites which use lignite as the feed. For this site, the steam generated in the gasifier must be augmented by steam imported from other plant systems.

#### 4.4 Technical Risks

Technical risk is considered to be a condition or frequently occurring malfunction which prevents the consistent achievement of technical objectives.

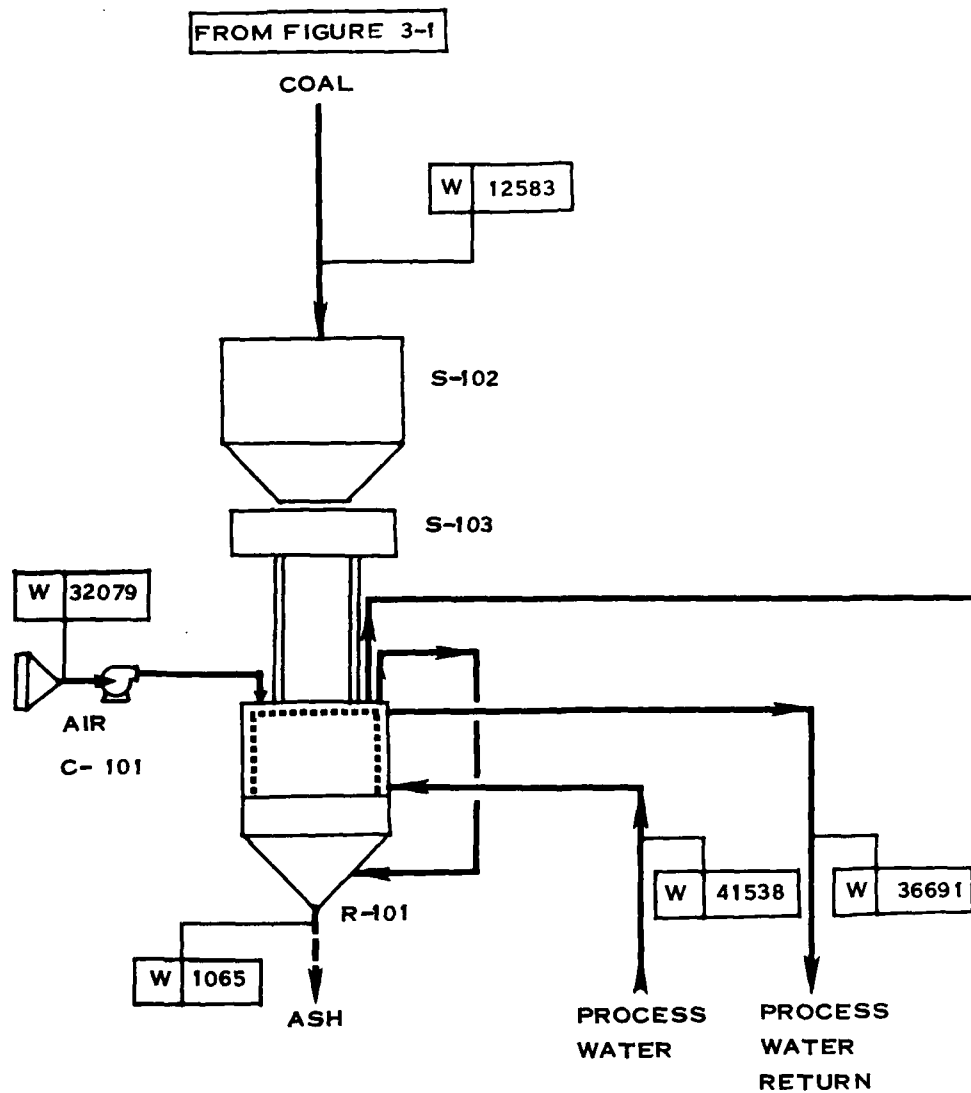
The mechanical components can be considered as potential technical risks. These components include the coal feed system, the agitator and the moving grates. However, the potential problems in these areas have been virtually eliminated by the design improvements made in the course of many commercial applications. The design features now include replaceable bushings and oversized ball thrust bearings with oil and grease dams for the revolving grate assembly.

The agitator arm and its vertical drive shaft made of heavy water-cooled steel tubing with the wear parts protected by heat and wear resistant castings. Because of the design features the technical risk for the mechanical components is minimal.

Consideration must be given to the possibility that the feed coal contains more fines than can be tolerated by the gasifier. The Wellman-Galusha gasifier can accept up to 15% of its coal feed in sizes



below 1/4 inch. If the percentage of fines exceeds 15%, the pressure differential across the coal bed can be excessive, and there can occur a high carryover of ungasified coal into the cyclone. This condition can have a significant impact on the efficiency of operation. Provision must be made for disposition of fines if they exceed the allowable percentage. A possible solution is to divert the excess coal fines to a nearby coal burning facility. If this utilization of the excess fines is not possible, than briquetting equipment must be provided. The tars generated from the gasification step can be used as the binder in the briquetting operation. The use of briquetts in the gasifier represents a technical risk. If the briquettes are not mechanically strong enough to withstand the temperature and abrasion they will breakup into fines. then all of the potential problems described for fines can occur. Various bench scale tests can be made to minimize the risk of briquette breakdown but only actual operation with the design coal can be definitive.



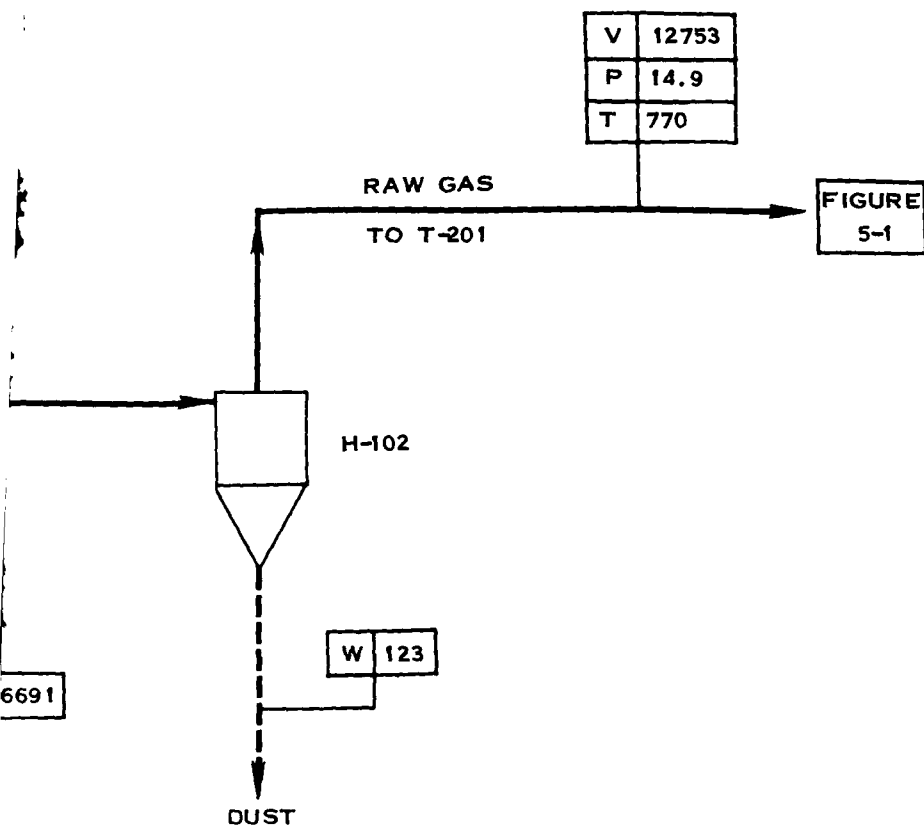
SYMBOLS:

V - VOLUME FLOW, CFM

W - FLOW, LB/HR

P - PRESSURE, PSIA

T - TEMPERATURE, °F



1/29/1985

DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

PROCESS FLOW DIAGRAM

COAL GASIFICATION SECTION

FIGURE 4-1

EBASCO SERVICES INCORPORATED

# Wellman Galusha Gas Producer Fuel Valves

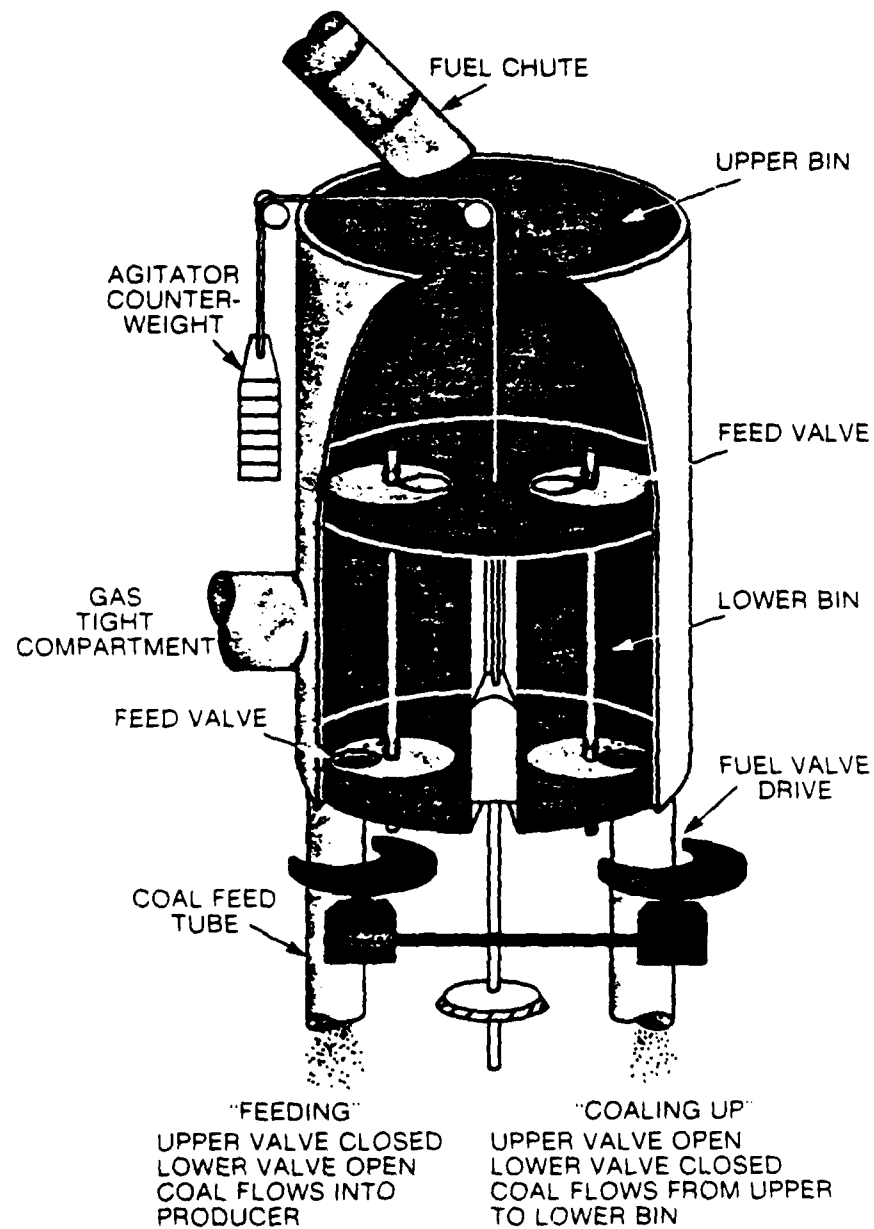


FIGURE 4-2 FEED MECHANISM

## Wellman Galusha Gas Producer Chamber

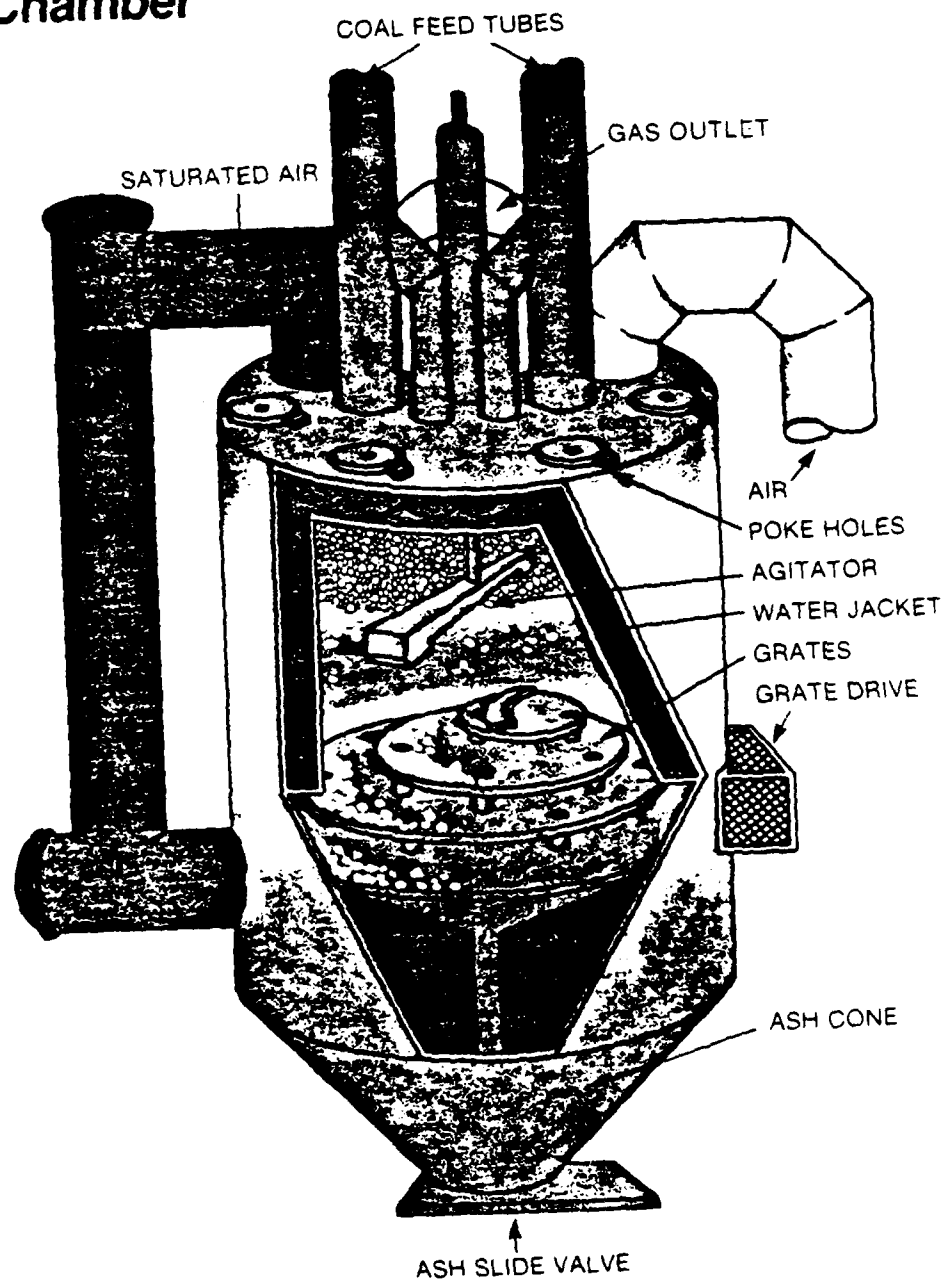


FIGURE 4-3 REACTION CHAMBER

TABLE 4-1

## SUMMARY OF CHARACTERISTICS FOR COMMERCIALIZED GASIFICATION TECHNOLOGIES

Type	Lurgi Dry Ash		Koppers-Totzek		Winkler		Wellman-Galusha		Woodell-Luckham/ Gas Integral		Stolic	
	Fixed Bed	Entrained Flow (Slagging)	Fluidized Bed	Fixed Bed (Single & Two Stages)	Fixed Bed (Two Stages)	Fixed Bed (Two Stages)	Fixed Bed (Two Stages)	Fixed Bed (Two Stages)	Fixed Bed (Two Stages)	Fixed Bed (Two Stages)	Fixed Bed (Two Stages)	Fixed Bed (Two Stages)
Operating Conditions: Temperature (°F)	2000 Combustion Zone 1500 Gasification Zone 800 Exiting Gas 350-450	3500 Combustion 2700 Off Gas	1800-2100 Fluidized Bed 1700-2000 Off Bed Gases	2400 Combustion Zone 1000 Exiting Gas	2200 Gasification Zone 1200 Clear Gas 250 Top Gas Atmospheric	1200 Bottom Ash 750 Hot Raw Gas 250 Top Gas Atmospheric	1200 Bottom Ash 750 Hot Raw Gas 250 Top Gas Atmospheric	1200 Bottom Ash 750 Hot Raw Gas 250 Top Gas Atmospheric	1200 Bottom Ash 750 Hot Raw Gas 250 Top Gas Atmospheric	1200 Bottom Ash 750 Hot Raw Gas 250 Top Gas Atmospheric	1200 Bottom Ash 750 Hot Raw Gas 250 Top Gas Atmospheric	1200 Bottom Ash 750 Hot Raw Gas 250 Top Gas Atmospheric
Pressure (psig)		0-15	0-45		Atmospheric	Atmospheric	Atmospheric	Atmospheric	Atmospheric	Atmospheric	Atmospheric	Atmospheric
Coal Requirements: Types	All types, preferably non-caking	All types, requires pretreatment drying to a moisture content of 1.8%	Wide variety, preferably non-caking	Single stage designed for low volatile coals (anthracite coke). Can accept bituminous peat & lignite if provided with stirrer.	Two stage designed for high volatile coals (bituminous)	Non-caking or weakly caking coal	Non-caking or weakly caking coal	Non-caking or weakly caking coal	Non-caking or weakly caking coal	Non-caking or weakly caking coal	Non-caking or weakly caking coal	Non-caking or weakly caking coal
Size	Sized Coal 1/4" x 2"	Pulverized coal 70% less than 200 mesh	Crushed coal smaller than 3/8"	Sized coal 3/4" x 2-1/2" for two stage, 1/4" x 4" for single stage	Sized Coal 1-1/2 x 1/2"	Sized Coal 2-1/2" x 3/4"	Sized Coal 2-1/2" x 3/4"	Sized Coal 2-1/2" x 3/4"	Sized Coal 2-1/2" x 3/4"	Sized Coal 2-1/2" x 3/4"	Sized Coal 2-1/2" x 3/4"	Sized Coal 2-1/2" x 3/4"
FSI	9 or less	-	2.5 (max)	6 (max)	Greater than 2100	Greater than 2200	Greater than 2200	Greater than 2200	Greater than 2200	Greater than 2200	Greater than 2200	Greater than 2200
Ash Fusion Temp.	Refractory as req'd	-	Refractory ash preferred	Sub-Bituminous Coal	Bituminous Coal	Bituminous Coal	Bituminous Coal	Bituminous Coal	Bituminous Coal	Bituminous Coal	Bituminous Coal	Bituminous Coal
Typical Gas Composition (% vol, dry)	Bituminous Coal Air Blown 24.0 16.0 4.0 14.0 41.0 1.0 160-180	Eastern Coal O <sub>2</sub> Blown 36.0 52.5 10.0 1.1 0.4 286	Sub-Bituminous Coal Air Blown 14.0 22.0 1.0 7.0 56.0 115-125	Bituminous Coal Air Blown 15.0 28.6 2.7 3.4 50.3 120-178	Bituminous Coal Air Blown 17.0 28.3 2.7 4.5 47.2 175-205	Sub-Bituminous Air Blown 17.37 31.15 1.80 2.69 45.89 0.10 160-200	Sub-Bituminous Air Blown 17.37 31.15 1.80 2.69 45.89 0.10 160-200	Sub-Bituminous Air Blown 17.37 31.15 1.80 2.69 45.89 0.10 160-200	Sub-Bituminous Air Blown 17.37 31.15 1.80 2.69 45.89 0.10 160-200	Sub-Bituminous Air Blown 17.37 31.15 1.80 2.69 45.89 0.10 160-200	Sub-Bituminous Air Blown 17.37 31.15 1.80 2.69 45.89 0.10 160-200	Sub-Bituminous Air Blown 17.37 31.15 1.80 2.69 45.89 0.10 160-200
By-Products	Tars Oils Naphtha Phenols Ammonia Sulfur	Sulfur	Sulfur	Tars Oils Coal Dust Sulfur	Tars Oils Coal Dust Sulfur	Tars Oils Coal Dust Sulfur	Tars Oils Coal Dust Sulfur	Tars Oils Coal Dust Sulfur	Tars Oils Coal Dust Sulfur	Tars Oils Coal Dust Sulfur	Tars Oils Coal Dust Sulfur	Tars Oils Coal Dust Sulfur

4-15

6/2/90

TABLE 4-1  
SUMMARY OF CHARACTERISTICS FOR COMMERCIALIZED GASIFICATION TECHNOLOGIES

	Lurgi Dry Ash	Koppers-Totzek	Winkler	Wellman-Ludlow	Woodall-Ketchum/ Gas Integrate	Stolic
Capacity	1300 TPD (oxygen blown) 600 TPD (air blown)	430-860 TPD (oxygen blown)	700 TPD (Atm. Pressure)	84-90 TPD	100 TPD	70-90 TPD
Turn-Down (% of design)	25	65	25	10	25	5/20 (manually/ automatically)
Commercial Application	Proven since 1936 18 plants installed worldwide	Proven since 1949, over 30 plants worldwide	Proven since 1926, 63 plants installed- 38 currently operating	Proven since 1930, 12 plants operating in the U.S. - over 150 plants worldwide	Proven in over 100 plants outside the U.S.	Proven during the last 40 years About 30 plants oper- ating in S. Africa & Europe 1 improved plant in the U.S. (FM- STOLIC).

TABLE 4-2  
SUMMARY OF CHARACTERISTICS FOR SECOND GENERATION GASIFICATION TECHNOLOGIES

	British Gas/Slagging Lurgi	KUN	Texaco	U-Gas
	Fixed Bed (Slagging)	Fixed Bed	Entrained Flow (Slagging)	Fluidized Bed
2800 Slagging Zone		1500-2100	2300-2600	1750-1900
1500 Gasification Zone		800 Exiting Gas		
850 Exiting Gas		15-450	15-1200	50-350
350-450				
Major testing has been done on sub-bituminous & lignite coals. Coals w/high content of re-fractory ash require use of flux agent	Non-caking coals. High moisture coals require predrying. Has been tested on anthracites & bituminous coals	All types. Coal with re-fractory ash require special consideration	All types. Caking coals need pretreatment. High moisture coals require drying	
Graded coal 1/4" to 3" - Currently testing for fines limitation	Graded coal similar to Lurgi & coal briquettes weighting approx. 3 grams ea.	55%-67% solids slurry coal crushed to less than 14 mesh	1/4" x 0" crushed coal	
9 or less	3	-	8 or less	
No Limitation	-	2600 max.	2650	
Bituminous (oxygen blown)	Bituminous (air blown)	Bituminous (oxygen blown)	Bituminous (oxygen blown)	
31.8	26.0	36.0	40.7	
55.0	15.0	48.5	33.0	
3.5	13.8	12.3	21.0	
5.0	2.0	0.9	3.0	
3.4	43.0	1.0	1.0	
1.3	0.2	1.3	1.3	
350	167	275	275	
Tars				
Oil				
Naphtha				
Phenols				
Ammonia				
Sulfur				

Operating Conditions	
- Temperature of	
- Pressure (psig)	
Coal Requirements	
- Types	
- Size	
- FSI	
- Ash Fusion Temp.	
Typical Gas Products	
- Coal basis	
- Composition (Vol %, Dry)	
H <sub>2</sub>	
CO	
CH <sub>4</sub>	
N <sub>2</sub>	
H <sub>2</sub> S + COS	
HHV Btu/SU	
By Products	
Sulfur	

4-17

4-17



TABLE 4-2  
SUMMARY OF CHARACTERISTICS FOR SECOND GENERATION GASIFICATION TECHNOLOGIES

Type	British Gas/Slagging Lurgi		KUN		Texaco		D-Gas	
	Fixed Bed (Slagging)		Fixed Bed		Entrained Flow (Slagging)		Fluidized Bed	
PLANT CAPACITY, TPD	400-800		24-48		1000		30 (2nd in construction)	
DEVELOPMENT STAGE	Near Commercial		Pilot Plant		Near Commercial (coal) Commercial (oil)		Pilot Plant. Demonstration unit expected to be operating in 1986	

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4-114

TABLE 4-3  
GASIFICATION DESIGN CRITERIA  
ANCHORAGE, ALASKA

COAL (LIGNITE A TO SUBBITUMINOUS C)

Proximate analysis (as received, %)	
Moisture	22.3
Ash	16.4
Volatiles	35.6
Fixed Carbon	25.7
Ultimate Analysis (dry basis %)	
Carbon	52.0
Hydrogen	4.8
Nitrogen	1.0
Sulfur	0.3
Chlorine	-
Ash	21.1
Oxygen (by diff)	20.8
High heating value (as rec'd Btu/Lb)	6950
Ash Fusion, Initial Def (°F)	2264
Free Swelling Index	Less than 1
Estimated Feed (TPD, as rec'd)	To be determined

TABLE 4-4  
GASIFICATION DESIGN CRITERIA  
FORT HOOD, TEXAS

COAL (LIGNITE)

Proximate analysis (as received, %)

Moisture	32.25
Ash	15.13
Volatiles	29.81
Fixed Carbon	22.11

Ultimate Analysis (dry basis %)

Carbon	56.03
Hydrogen	4.13
Nitrogen	1.07
Sulfur	1.56
Chlorine	0.03
Ash	22.34
Oxygen (by diff)	14.84

High heating value (as rec'd Btu/Lb)

6118

Ash Fusion, Initial Def (°F)

2300 red

2354 (OX)

Free Swelling Index

Less than 1

Estimated Feed (TPD, as rec'd)

To be determined

TABLE 4-5  
GASIFICATION DESIGN CRITERIA  
SCRANTON, PENNSYLVANIA

COAL (ANTHRACITE)

Proximate analysis (as received, %)

Moisture	4.3
Ash	9.3
Volatiles	4.4
Fixed Carbon	82.0

Ultimate Analysis (dry basis %)

Carbon	84.1
Hydrogen	2.6
Nitrogen	0.9
Sulfur	0.6
Chlorine	-
Ash	9.8
Oxygen (by diff)	2.0

High heating value (as rec'd Btu/Lb)	13,020
Ash Fusion, Softening, H=W (°F)	2660-3000
Free Swelling Index	Less than 1
Estimated Feed (TPD, as rec'd)	To be determined

TABLE 4-6  
GASIFICATION DESIGN CRITERIA  
WASHINGTON, D.C.

SITE CONDITIONS

Elevation (above SL, ft)	14
Design Atm pressure (psia)	14.7
Ambient temp conditions (°F)	14 to 95
Summer Design DB/WB (°F)	93/75
Winter Design DB (°F)	14

COAL (EASTERN KENTUCKY BITUMINOUS)

Proximate analysis (as received, %)	
Moisture	5.78
Ash	7.74
Volatiles	38.42
Fixed Carbon	48.06
Ultimate Analysis (dry basis %)	
Carbon	70.21
Hydrogen	5.05
Nitrogen	1.44
Sulfur	1.70
Chlorine	0.04
Ash	8.21
Oxygen (by diff)	13.35
High heating value (as rec'd Btu/Lb)	13,000
Ash Fusion, Initial Def (°F)	2266 (red)
Free Swelling Index	4.0
Estimated Feed (TPD, as rec'd)	151

## 5.0 GAS PROCESSING

### 5.1 Introduction

The raw gas produced in the Gasification Section flows to the Gas Processing sections of the plant where it is cooled, cleaned and converted to a hydrogen rich stream suitable as feed for the fuel cell.

The Gas Processing module includes the gas cooling, cleaning and compression, the CO Shift and the Gas Desulfurization Sections, where the raw gas is processed to meet the specifications of the anode fuel. It also includes a Process Condensate Treatment Section, where the toxic and organic matter are removed from the process waste water to satisfy the environmental requirements for discharged effluents.

### 5.2 Process Selection Rationale

The processes involved in the Gas Processing System and the reason for selecting the proposed plant configuration are discussed in this section of the report.

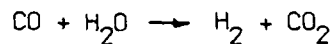
#### 5.2.1 Gas Cooling, Cleaning and Compression

The gasifier effluent is at 770°F and atmospheric pressure. This gas contains vapors of tars, oils, phenol, ammonia and particulates that must be removed before the gas is compressed to the pressure required for the fuel cell. The hydrocarbons, ammonia and particulates can damage the gas compressor and can cause the clogging of the catalysts located downstream of the gas cleaning section. By cooling the gas the hydrocarbons will condense and can be easily removed by physical separation processes. The ammonia and dust particles are removed by scrubbing with water. The series of processes used to clean and cool the raw gas have been developed through many years of experience in treating raw gases from fixed bed gasifiers and coke oven gases. The cooling of the gas is achieved by direct contacting with water in a saturator, by spraying with water followed by the removal of the condensed hydrocarbons in a dispersed phase electrostatic precipitator. The final gas cooling and

removal of traces of oil and tars is done by scrubbing with water in a primary cooler provided with a venturi scrubber. After the primary cooler, the cooled clean gas is compressed in a three stage centrifugal compressor, with interstage cooling and condensate separation. The compressed gas, still containing traces of ammonia, will be washed with a dilute sulfuric acid solution in the ammonia sulfate saturator before being sent to the CO Shift Section. The ammonia content of the clean gas is reduced by this treatment to 0.5 ppm V, to satisfy the requirements of the fuel cell.

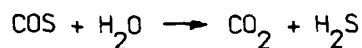
#### 5.2.2 CO Shift

The function of the CO Shift is to reduce the CO content and increase the hydrogen content of the fuel gas to levels suitable for fuel cell operation. This is achieved by the exothermic reaction of CO with steam according to the water gas shift reaction:



The reaction is carried over a catalyst with great release of heat. There are several CO Shift catalysts on the market, each having maximum activity within a specific range of temperatures. Some of the catalysts can tolerate sulfur in the gas, others are poisoned by it.

The presence of sulfur compounds in the fuel gas led to the selection of a highly active sulfur tolerant COMO shift catalyst. The catalyst is activated by small amounts of sulfur in the gas and it is active within a wide range of temperatures. When operating at lower temperature, it also promotes the hydrolysis of carbonyl sulfide (COS) according to the reaction:



A two stage shift reaction with the second bed operating at lower temperatures was selected for this application. Both reactions, the CO shift and the COS hydrolysis take place simultaneously, but the bulk of COS hydrolysis occurs in the second bed. This design will achieve the desired CO conversion and will reduce the COS concentration in the gas to about 30 ppm by volume. The total  $H_2S$  content of the fuel gas is increased after the COS conversion.

### 5.2.3 Sulfur Removal and Recovery

During the gasification process the sulfur in the coal is converted mainly to  $H_2S$ , with some COS and traces of organic sulfur compounds.

The specifications for the anode fuel require a maximum sulfur content of 4 ppm (Vol). Virtually, total sulfur removal from the gas must be achieved.

There are a number of sulfur removal processes commercial available, for treating the  $H_2S$  bearing gases. These processes include chemical and physical absorption systems, which remove the sulfur compounds from the gas down to the desired level. The sulfur compounds and  $CO_2$  dissolved are then separated from the solvent as an acid gas. The concentration of  $CO_2$  in the acid gas depends on the selection of the sulfur removal process. The acid gas is then treated in an additional step, to recover the sulfur from the acid gas as elemental sulfur.

The physical absorption processes such as Rectisol and Selexol are suitable for selectively removing the  $H_2S$  from a  $CO_2$  rich gas stream. These processes operate at low temperature levels and high acid gas partial pressures.

The chemical absorption processes using amines and hot carbonate, are not selective and remove the  $CO_2$  together with the  $H_2S$ . This feature leads to large steam consumptions for the regeneration the solvent.

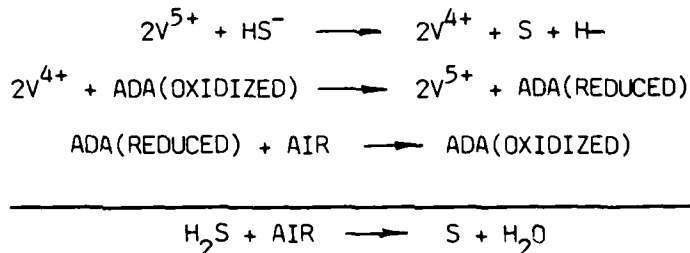
The gas produced by an atmospheric gasification such as the Wellman-Galusha gasifier has a very low  $H_2S$  partial pressure due to the dilution of the gas with the nitrogen from the air used in the



gasification process and the relatively low gas pressure even after the gas compression (100 to 160 psia). This low  $H_2S$  partial pressure eliminates the physical absorption systems as possible process choices. The chemical absorption processes, are a costly alternative for the sulfur recovery process due to the high  $CO_2$  concentration in the gas (24% Vol).

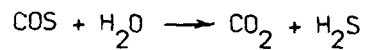
Therefore a Sulfur Removal process was selected to satisfy the particular requirements of this application. It is a liquid oxidation Stretford type of plant which removes  $H_2S$  at any concentration level and in a wide range of pressures, and recovers sulfur in elemental form without the need of an additional sulfur recovery plant.

The chemistry of the Stretford Process is quite complex. In this process,  $H_2S$  is chemically oxidized by sodium vanadate at a pH of 9.0 into sulfur and water. The pentavalent vanadic salt is reduced to the quadri-valent vanadous form and regenerated to its vanadic form in an oxidizer vessel by air-sparging. The chemical additive ADA (anthraquinone disulfonic acid) serves as an accelerator for the oxidation of vanadium by air as shown below:



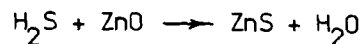
The air converts the reduced vanadium into vanadate and also acts as a flotation agent by frothing out the product sulfur. This,  $H_2S$  is, in effect, oxidized by air into sulfur and water, with the vanadium and ADA acting as an intermediary oxidant.

Because the Stretford process cannot remove COS, a hydrolysis step is required to convert COS to  $H_2S$  according to the following reaction:



A highly active catalyst, Haldor Topsoe CKA activated alumina will be used to reduce the COS to levels accepted by the fuel cell operation. This catalyst can promote hydrolysis effectively at a relatively low temperature.

The final polishing of the gas where traces of  $\text{H}_2\text{S}$  are removed is achieved over Zinc Oxide (ZnO) beds where the following reaction takes place:



The ZnO beds are sulfur guard beds used to bring down the sulfur content of the anode fuel and to protect the fuel cell from process upsets. After the polishing step the total sulfur content of the gas is represented by traces of COS which are not adsorbed by ZnO. This sulfur content will not exceed the 4 ppm requirement of the fuel cell.

ZnO is commonly used in gas cleaning operations. It was selected over the iron oxide alternative being considered to have more reliable performance.

#### 5.2.4 Process Condensate Treatment

The process recycled process condensate from the gas cooling section contains phenols, ammonia, cyanides and hydrogen sulfide. To prevent the buildup of these products in the circulating waste water, a purge stream is removed from the process condensate and discharged as waste water effluent. Before being discharged the waste water is treated for the removal of the pollutants. Two processes were considered to be used for this purpose: the Wet Air Oxidation Process (WAO) and the Powdered Activated Carbon Treatment (FACT).

Wet air oxidation takes place by a family of related oxidation and hydrolysis reactions in a pressurized reactor with injection of air and steam. These reactions lead to total destruction of the organic compounds to carbon dioxide and water.

The PACT process uses powdered activated carbon in conjunction with conventional biological treatment to remove contaminants. Biodegradables are biologically treated and simultaneously the non-biodegradable pollutants are absorbed. The spent carbon and waste biomass are separated as a sludge which can be disposed of or, if the capacity of the system is large enough, a regeneration unit can be installed to regenerate the carbon for recycle. PACT removes most carbonaceous contaminants and biologically converts the ammonia to nitrate and nitrate in a single step.

The process selected for the Process Condensate Treatment Section is an ammonia stripping process which removes most of the  $\text{NH}_3$  followed by a PACT system because the PACT process has substantially lower investment costs for this size plant than the WAO. A dilution step by the addition of recycled treated effluent was provided to insure that the toxicity of the waste water feed will not be too high for the biological treatment. The carbon regeneration step was not included because it is typically not justified for systems of this size.

### 5.3 Description of Gas Processing System

#### 5.3.1 Design Criteria

The gas processing module of the plant will be designed to produce a gas according to the anode feed gas specifications, as shown on Table 6-3.

The basis of design for the Process Condensate Treatment Section is to produce a liquid effluent suitable for discharge outside the plant's battery limits. The quality of the treated effluent is indicated on Table 5-1.

### 5.3.2 Process Description

#### 5.3.2.1 Gas Cooling, Cleaning and Compression

The configuration of the Gas Cooling Cleaning and Compression Section is given in Figure 5-1.

The hot gases leaving the gasification section contain some entrained particulates as well as vaporized tars and oils. The gases are first adiabatically cooled to saturation by recirculating liquor through the saturator. This direct contact water wash condenses the vaporized tars and oils, mixes the oily droplets with the scrubber water and removes additional particulates. The larger drops of oil are removed by the liquor, the smaller size, particles remain entrained in the gas. Further mist and particulate matter are removed in the dispersed phase electrostatic precipitator. In the electrostatic precipitator the negatively charged particles dispersed in the gas are attracted to the positively charged collecting elements and discharged from the system.

Final cooling of the gas is effected in the primary cooler by contacting the gas in a jet venturi with externally cooled circulating liquor. The cooling causes further condensation of hydrocarbons and water vapor.

Purge streams from the circulating saturation liquor and primary cooler are sent to a liquid phase electrostatic precipitator where the condensed tars and oils are separated. The water phase is recycled to the saturator and the mixture of warm water and condensed oils/tars from the precipitator is combined with that from gas compression intercooler KO drums and delivered to a tar separator via the liquor collection tank. The tars and oils separated by gravity from the water are combined with those removed in the electrostatic precipitator and maintained in a liquid state in the steam heated tar collection tank. From here, the tar/oil is pumped off site. A portion of the tars may be used as a binder in a briquetting unit for coal fines. Part of the water overflow from the tar separator is circulated to the saturator to maintain water balance. The remaining overflow serves as system blowdown and is sent to the Process Condensate Treatment Section.

TABLE 5-1

TREATED PROCESS EFFLUENT CHARACTERISTICS\*

	<u>mg/l</u>
COD, **	150
Phenol,	1
HCN,	0
NH <sub>3</sub> ,	1
H <sub>2</sub> S,	0
Suspended Solids,	20

\* As per communication with Zimpro Environmental Control Systems

\*\* COD = Chemical Oxygen Demand

The gasification of anthracite does not generate tars and oils. This precludes the needs of the hydrocarbons removal system for sites based on the use of anthracite coal.

Multistage centrifugal compression with interstage cooling is provided to increase the gas pressure. Condensate, consisting of hydrocarbons and water, produced in the water cooled interstage coolers is returned to the liquor collection tank in the cooling/cleaning area.

The compressed and cleaned gas leaving the section is washed with sulfuric acid to remove ammonia not scrubbed out in the cooling and cleaning of the gas. The heat of this neutralization is removed by circulating the wash liquor through an external heat exchanger. The ammonia-free gas exits to the CO Shift section.

#### 5.3.2.2 CO Shift

The CO Shift reaction is carried out in two stages. It is a highly exothermic reaction and the heat of reaction is used to preheat the feed to the first stage to raise steam and to preheat the clean gas before the final polishing.

The configuration of the CO Shift Section is given in Figure 5-2. Scrubbed gas from gas compression is preheated by heat exchange and 1st stage shift effluents followed by direct injection of medium pressure steam. Upon further preheating against 1st shift effluent, the wet gas is introduced into the first stage reactor. After the reaction the first stage effluent is cooled by heat exchange with the feed. Further heat recovery takes place by generation of medium pressure steam, and the cooled first stage effluent is introduced into the second stage of water gas shift.

The second stage shift operates at a temperature lower than the first permitting further reaction of CO and COS to reduce the CO content to the desired level.

Second stage shift effluent is cooled by preheating anode feed gas and preheating raw gas feed to the first stage shift. Additional cooling of the shifted gas to a temperature suitable for its introduction to the Desulfurization Section is accomplished by air and water cooling. Steam condensate resulting from gas cooling is sent to the Thermal Management System.

#### 5.3.2.3 Gas Desulfurization

The Gas Desulfurization Section is depicted on Figure 5-3.

This section is designed to reduce the total sulfur content of the gas to 4 ppm, a level acceptable for the fuel cell operation and for compliance with the sulfur emission levels of the plant. A liquid phase oxidation Stretford Sulfur Removal Process is used for the removal of  $H_2S$  to the required level.

The shifted gas stream is contacted in a venturi contactor which consists of a venturi type jet mixer and an absorber with the alkaline solution containing sodium vanadate. The  $H_2S$  is here oxidized by the sodium vanadate to elemental sulfur and water. The solution is sent to an oxidizer tank where by air spraying and in the presence of a ADA the vanadium is oxidized regenerating the alkaline solution and the product sulfur is separated by flotation. The regenerated solution is sent to the balance tank and recycled to the absorber. The sulfur slurry, separated from the solution, flow to the slurry tank and it is separated from chemicals by filtering combined with water washing. The sulfur is then reslurried with wash water and heated to the melting point. The molten sulfur flows from the decanter to the sulfur pit. The chemicals are returned to the system and the wash water is discarded.

Product gas leaving the absorber is preheated to fuel cell temperature in the CO Shift Section before being returned to the Gas Desulfurization Section for final polishing.

The main purpose of the final polishing process is to protect the fuel cell power section in the event of an upset in the sulfur removal plant.

It also provides also for the removal of the remaining COS which is not absorbed in the Stretford solution.

The preheated gas is put through a bed of low temperature hydrolysis catalyst, to convert almost all COS to  $H_2S$ . The  $H_2S$  is then removed down to the required level by absorption in a zinc oxide bed. The final polished anode gas is then sent to the fuel cell.

In the Stretford process, there is a by-product fixation of  $H_2S$  into thiosulfate. To avoid the accumulation of thiosulfate and thiocyanate, the solution is purged by removing a slip stream. This liquid effluent is treated in a proprietary Stretford reductive incineration process, which is a zero discharge process, overcoming the problem of disposing of waste liquors containing vanadium. The process also recovers all the vanadium and sodium salts removed from the process.

#### 5.3.2.4 Process Condensate Treatment

The Process Condensate and Treatment Section is depicted on Figure 5-4.

##### Ammonia Stripping

Water blowdown from the Tar Separator of the Gas Cooling and Compression Section is accumulated in the Sour Water Storage Tank. It is pumped to the Ammonia Stripper where ammonia and some phenols are removed by steam stripping. Heat economy for steam consumption is effected by heat exchange of stripper bottoms with incoming feed. Overhead vapors from the Ammonia Stripper are flared while stripper bottoms are sent to the Waste Water Treatment Sub-section for further processing.

##### Water Treatment

Water leaving Ammonia Stripping is further treated in the Waste Water Treatment sub-section. A powdered Activated Carbon Treatment (PACT) process is used to produce a waste water adequate for discharge. Raw water entering the system is first diluted by addition of recycle



effluent water. Virgin carbon is added to the diluted waste water as it flows into the contact-aeration tank. In the aeration tank the waste water is aerated in the presence of powered activated carbon, biomass, and inert ash. Mixed liquor dissolved oxygen level is maintained to insure optimum treatment.

To aid in solids settling, polymer is added to the mixed liquor as it flows to the system clarifier. In the clarifier, the solids are settled out and a portion of the clarifier overflow is discharged. No further treatment of this effluent discharge is required. The remainder of the clarifier overflow is recycled for dilution of incoming feed.

Clarifier underflow solids are continuously recycled to the aeration tank to maintain the high mixed liquor solids concentration. Spent carbon and biomass from the clarifier underflow are filtered before disposal. Filtrate water is combined with effluent recycle for dilution of feed.

### 5.3.3 Flexibility of Operations

The processes and equipment necessary to clean anode gas fuel from the Wellman-Galusha gasifier effluent are basically the same regardless of the coal used as feedstock. Variations in the coal compositions would require some adjustments in operation which can be easily tolerated by the equipment. Variations in the gas flow rate greater than 50% turndown can be handled with no ill effect on the product quality, but with some negative impact on the plant efficiency.

The gas cooling and cleaning is achieved by scrubbing with liquids. In order to maintain the required operating conditions, the liquid circulation flow rate will have to be maintained even when the gas flow rate is reduced. The gas compressors are the most sensitive equipment to volume variations in the gas flow rate. To maintain proper operation a portion of the gas will be recycled to the suction of the compressor to compensate for the reduced flow rate of the feedgas. The consumption of energy per unit gas compressed will be increased in turndown case.

The CO Shift reactors will accept a turndown below 50% in the gas flow rate and as the space velocity will be reduced, the conversion rate will be improved. Difficulties in reaching the design reaction temperatures due to less reaction heat available for preheating the feed gas might arise from very low gas throughput.

The Stretford process has a high degree of flexibility in that it can tolerate wide variations in both gas feed rate as well as  $H_2S$  concentration, especially, when using a venturi contactor.

The ammonia stripping process in the Process Condensate Treating Section requires a good contact between the waste water and the live steam. If the liquid flow rate is reduced by more than 30% in order to maintain good operating conditions, the ammonia stripper could be operated intermittently at full rate, using waste water collected in the Sour Water Storage Tank.

The PACT waste water treatment system also has a high degree of flexibility and can accomodate wide variations in the composition and flow rate of the feed. The addition of dilution water gives the system the ability to adjust the composition of the waste water feed to the requirements of the PACT process.

#### 5.3.4 Site Specific Characteristics

As for coal gasification, the principal site characteristics that would affect the gas processing is the specific coal feed in each location.

The type of coal feed used and the requirements of the fuel cell determine the volume temperature and pressure of the gas to be processed. Those set of parameters, specific for each site are part of the basis of design for the gas processing units. The raw gas carries varied quantities of tars/oils, depending on the coal feedstock. The amount of tars to be removed determines the sizing of the gas cleaning portion of the plant. In the anthracite case, there is no need for this sub-section.

The Compressor Section will be sized according to the fuel cell pressure used (e.g., 120 psia in UTC and 70 psia in Westinghouse).

The CO Shift Section will be designed based on the required hydrogen flow to the fuel cell and composition of the feed gas to the shift reactors. The volume of the gas, the volume of the steam used and the total amount of condensate to be removed, are different for each site, determining the size and duty of the equipment in this section. The anode feed gas is preheated in the CO Shift Section by exchanging heat with the second reactor effluent. The gas cooling train design, downstream of the second reactor, will be influenced by the amount of heat removed for anode gas preheating, which depends on the required temperature in the fuel cell (e.g., 405°F in UTC and 375°F in Westinghouse).

The sulfur content of the coal feed varies for each location (from 0.3 percent to 1.7 percent), impacting subsequently on the sulfur removal plant's size.

The Stretford process used for gas desulfurization, although it has not been used extensively in coal gasification plants, has been used in the petrochemical industry and performed satisfactorily. The process uses relatively simple equipment items such as a venturi scrubber and circulating pumps, which will be provided with installed spares, to minimize process disruptions due to possible equipment failure. A potential economic risk will be the operating costs of the Stretford unit. Reports from operating Stretford plants have indicated higher chemical consumption than anticipated. The operating costs of the Stretford process are sensitive to the chemicals consumption, because the products used are expensive.

The front end process of the condensate treatment section is an Ammonia Stripping unit. Ammonia stripping is a well established process, where the variations of ammonia concentration in waste water are controlled by adjusting the steam injection.

The PACT process used in the process condensate treatment is a new advanced biophysical treatment system, which is not yet fully commercialized. Extensive testing of coal gasification waste waters was

performed in pilot plant operations. Ammonia stripping and Phenol extraction failure tests have confirmed that the PACT process provides continuous, reliable treatment, resistant to synfuels facility process upset. Experience has shown that following each organic stress test, the PACT process returned to optimum operation within 2 to 4 days.

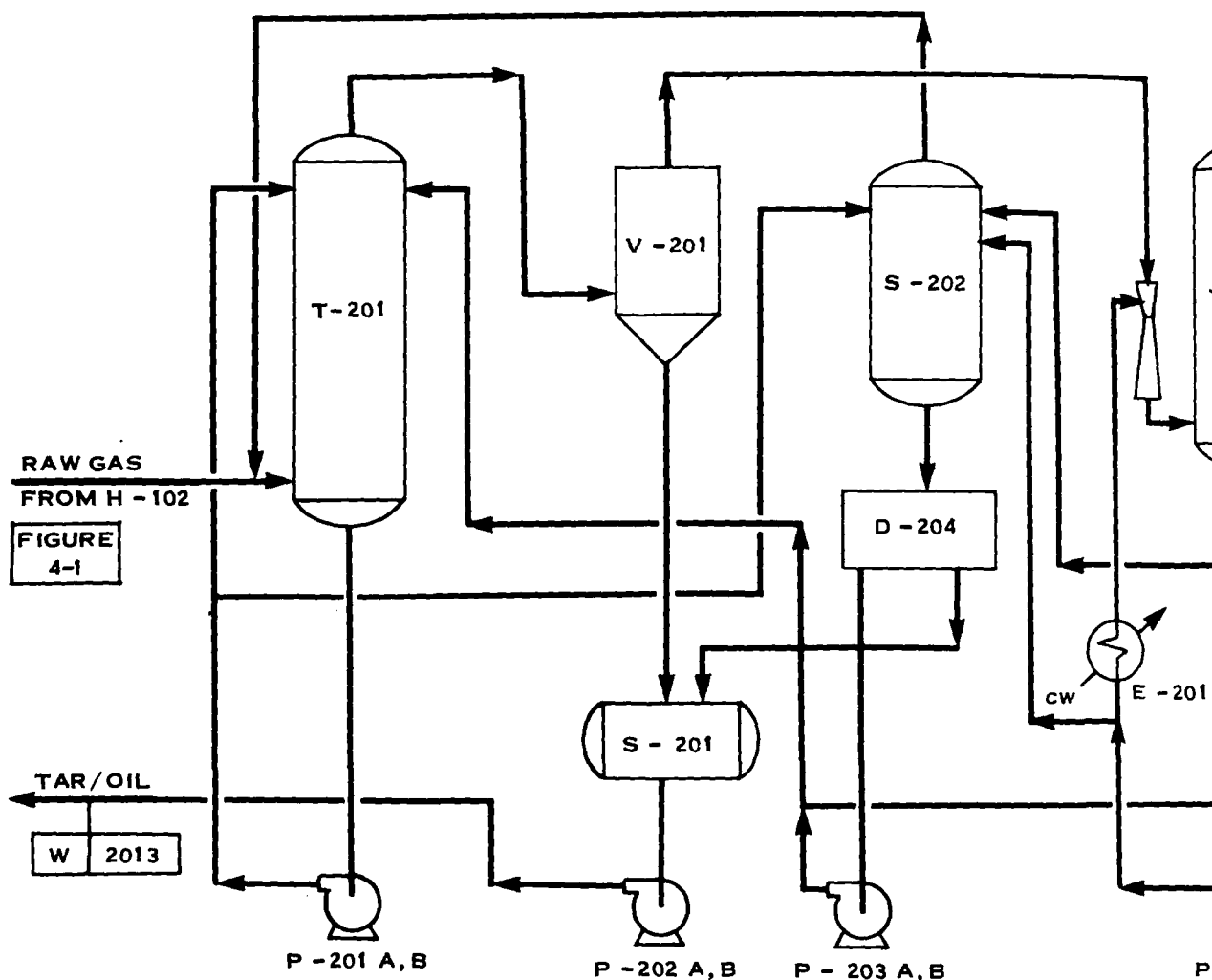
By providing excess capacity in the activated carbon feeding system and by providing for increased contact time in the aeration tank, the PACT system can be designed to overcome the risks of process upsets.

#### 5.4 Technical Risks

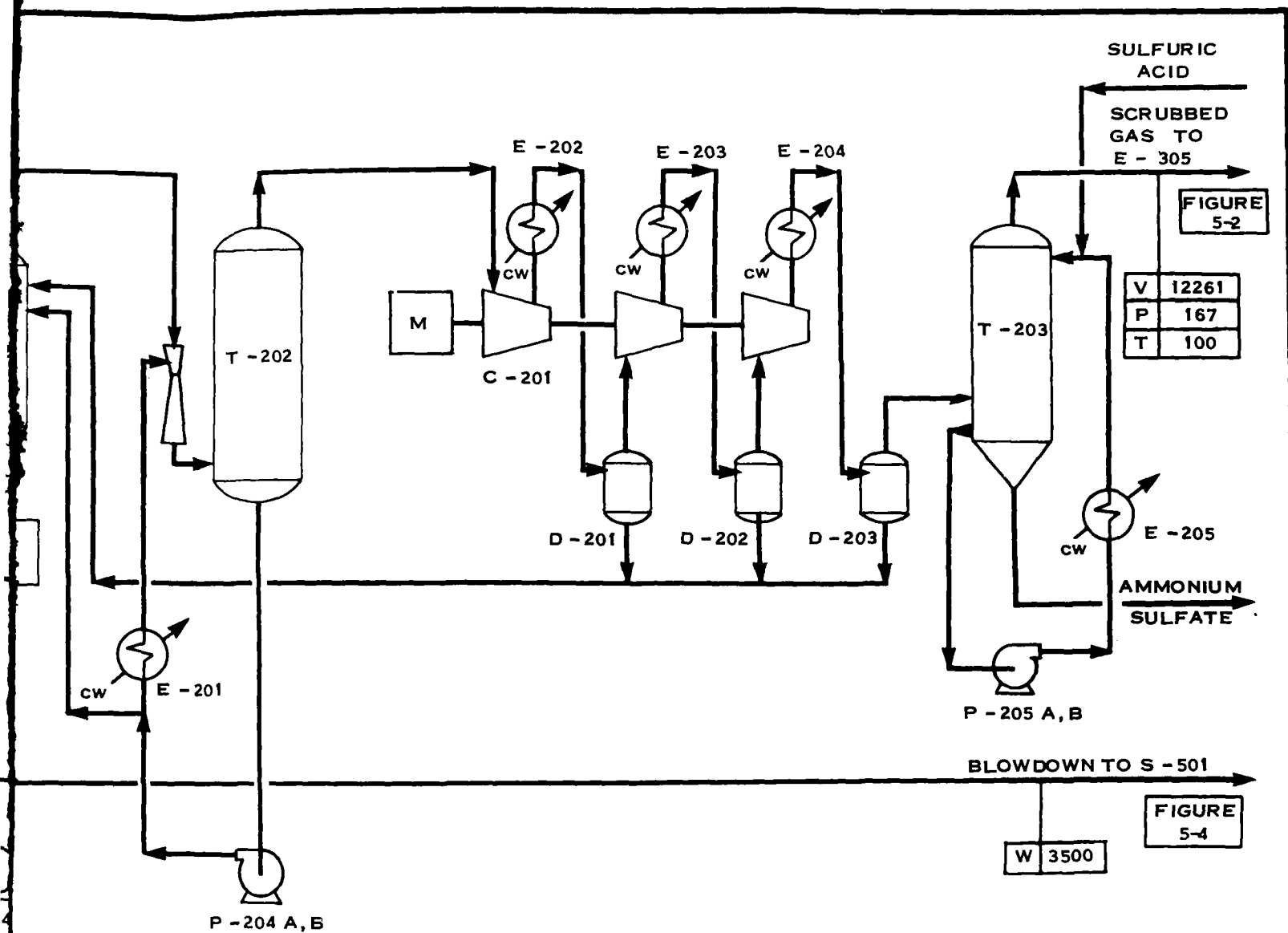
The equipment and processes used for Gas Cooling and Cleaning have been used in the coke oven industry in very similar applications. Additionally, there are Wellman-Galusha gasification plants in operation which currently use the spray cooling and electrostatic precipitators included in the design of this plant. The venturi scrubber used for final cooling and cleaning of the gas is of the type used in existing Texaco coal gasification plants.

The Gas Compressor might be considered as a potential high risk. It can be subject to corrosion and erosion from the gas components. During the detail design, special consideration will be given to avoiding condensation in the compressor and to the selection of suitable materials of construction.

The CO Shift section is not considered to be a high risk, as far as equipment failure and performance are concerned. The COMO sulfur tolerant catalyst, has been used successfully in the chemical industry. Currently there are three Texaco coal gasification projects (TVA, Texas-Eastman and Coolwater) which are using the catalyst without any indication of deterioration. The process conditions do not pose any fabrication problems, comparably sized equipment operating at similar pressures being relatively common. The economic risks associated with the catalyst utilization are not considered high, as failure would occur as a gradual reduction of activity as opposed to catastrophic failure or total inoperability. Hence, the risk can be evaluated purely in terms of the cost of recharging the reactors at greater frequency than expected.



T - 201	SATURATOR	P - 201 A, B	SATURATOR PUMP
V - 201	DISPERSED PHASE PRECIPITATOR	S - 201	TAR COLECTOR TANK
D - 204	TAR SEPARATOR	P - 202 A, B	TAR PUMP
S - 202	LIQUOR PHASE PRECIPITATOR	P - 203 A, B	LIQUOR PUMP
T - 202	PRIMARY COOLER	P - 204 A, B	PRIMARY COOLER PUMP
C - 201	GAS COMPRESSOR	D - 201	1ST STAGE K.O. DRUM
E - 202	1ST STAGE INTERCOOLER	D - 202	2ND STAGE K.O. DRUM
E - 203	2ND STAGE INTERCOOLER	D - 203	3RD STAGE K.O. DRUM
E - 204	3RD STAGE INTERCOOLER	P - 205 A, B	ACID CIRCULATION PUMP
T - 203	AMMONIUM SULFATE SATURATOR	E - 205	AMONIA SCRUBBER COOLER



SYMBOLS:

V - VOLUME FLOW, CFM

W - FLOW, LB/HR

P - PRESSURE, PSIA

T - TEMPERATURE, °F

1/29/1985

DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

PROCESS FLOW DIAGRAM

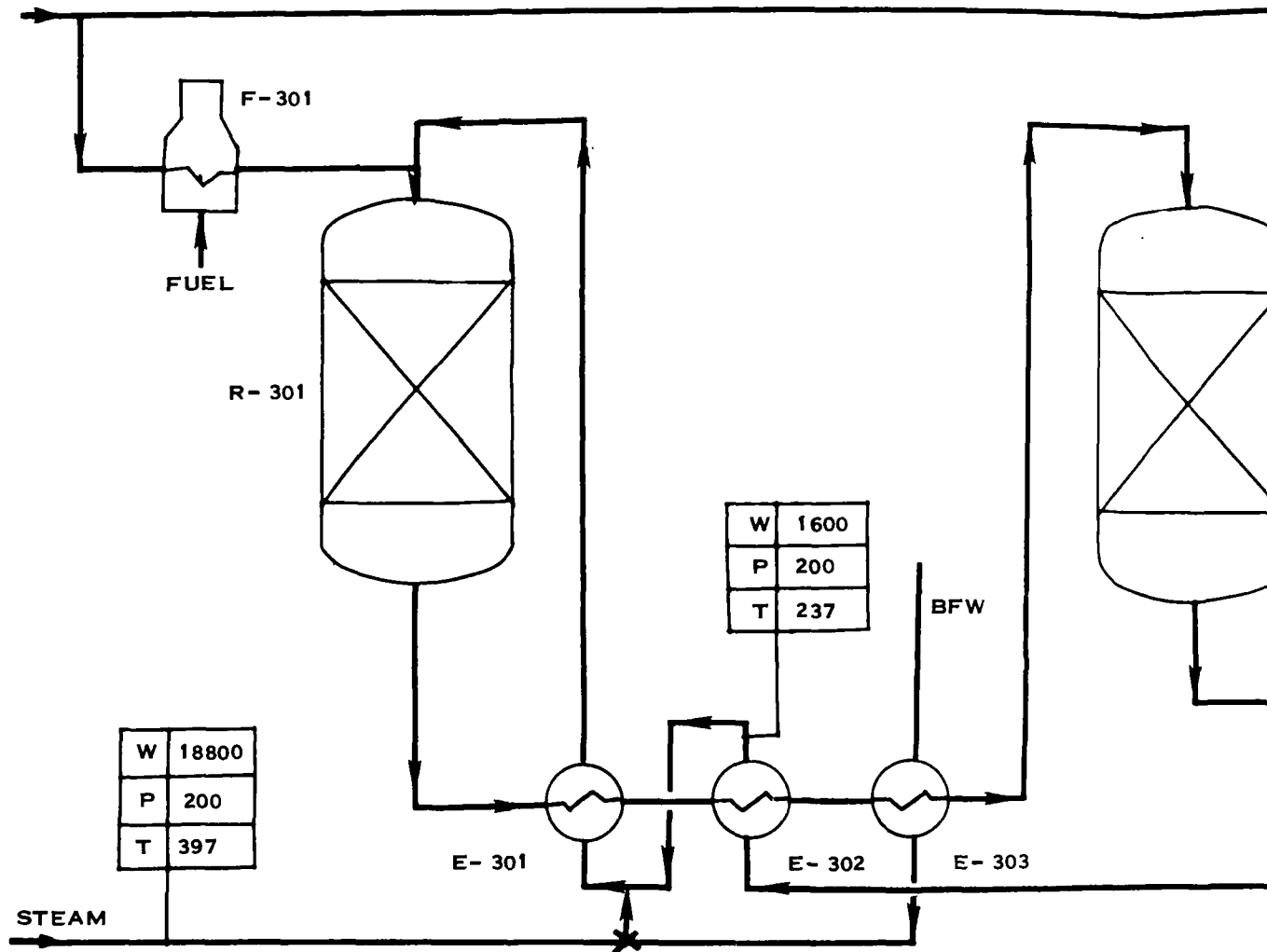
GAS COOLING, CLEANING AND  
COMPRESSION SECTION

FIGURE 5-1

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FIGURE  
5-1

SCRUBBED GAS FROM T- 203



D-301	K.O. DRUM
D-302	TRIM COOLER K.O. DRUM
E-301	FEED/EFFLUENT HEAT EXCHANGER II
E-302	FEED/EFFLUENT HEAT EXCHANGER I
E-303	CO SHIFT STEAM GENERATOR
E-304	FUEL CELL FEED HEATER

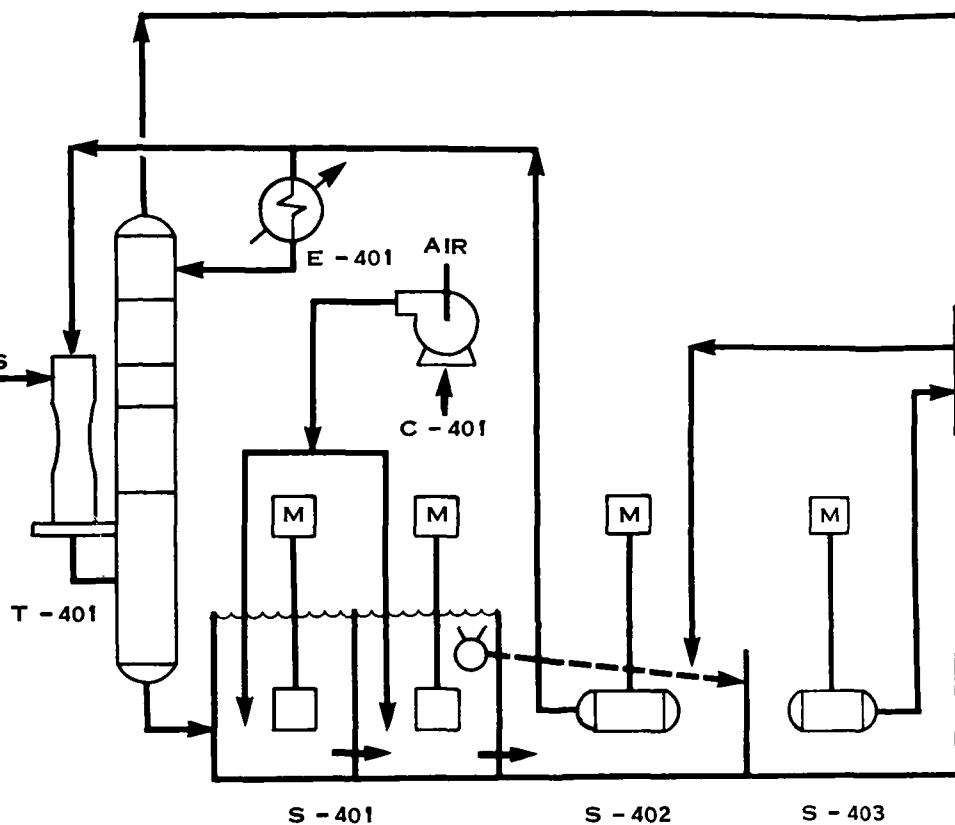
E-305
E-306
E-307
F-301
R-301
R-302





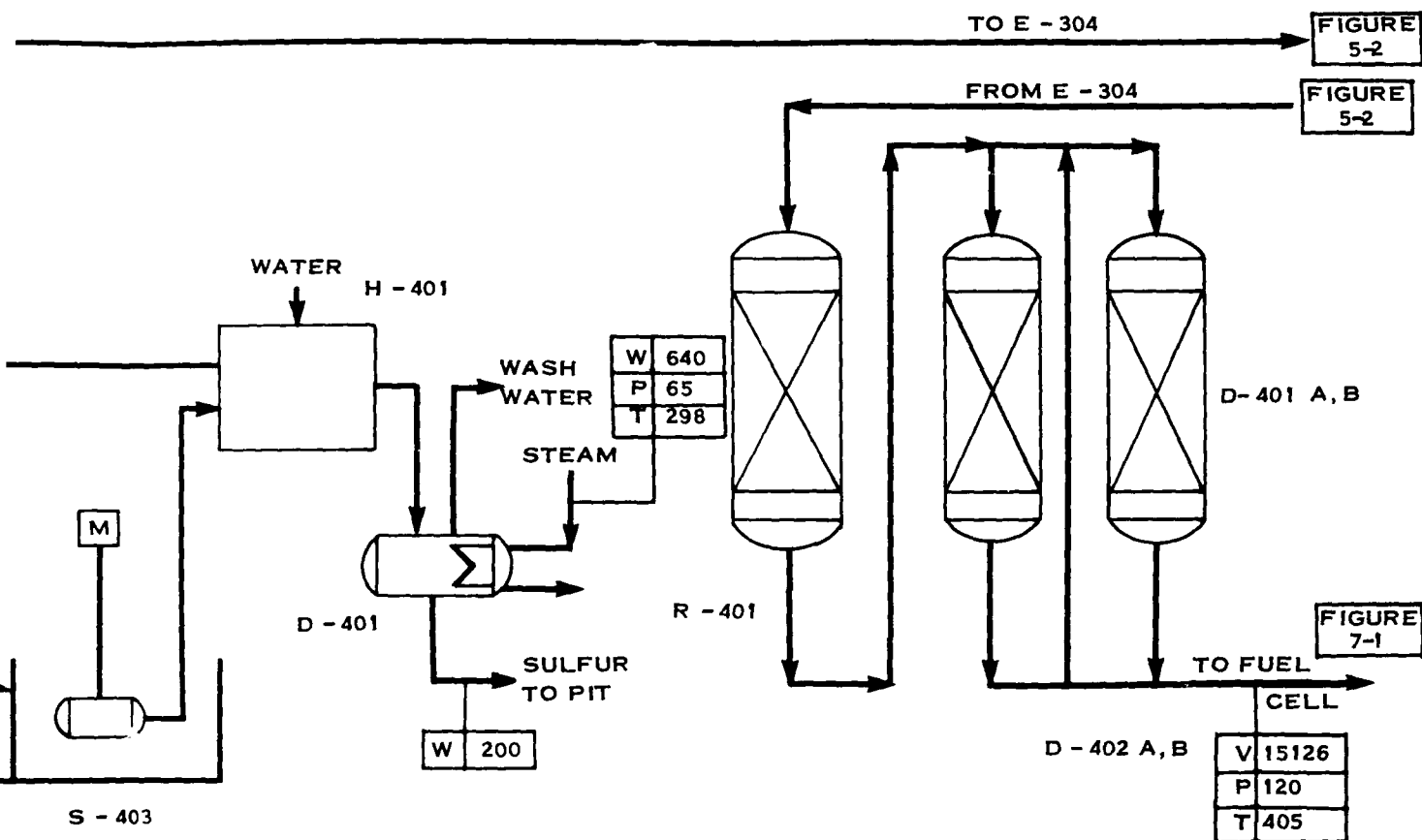
FIGURE  
5-2

SHIFTED GAS  
FROM D - 302



T - 401	VENTURI CONTACTOR
E - 401	SOLUTION HEATER
C - 401	AIR BLOWER
H - 401	SOLID SEPARATION WASH & RESLURRY
D - 401	SLURRY DECANter
R - 401	HYDROLYSIS REACTOR
D - 401 A, B	ZnO DRUM
S - 401	OXIDIZER TANKS
S - 402	BALANCE TANK
S - 403	SLURRY TANK

S  
V  
W  
P  
T



SYMBOLS:

V - VOLUME FLOW, CFM

W - FLOW, LB/HR

P - PRESSURE, PSIA

T - TEMPERATURE, °F

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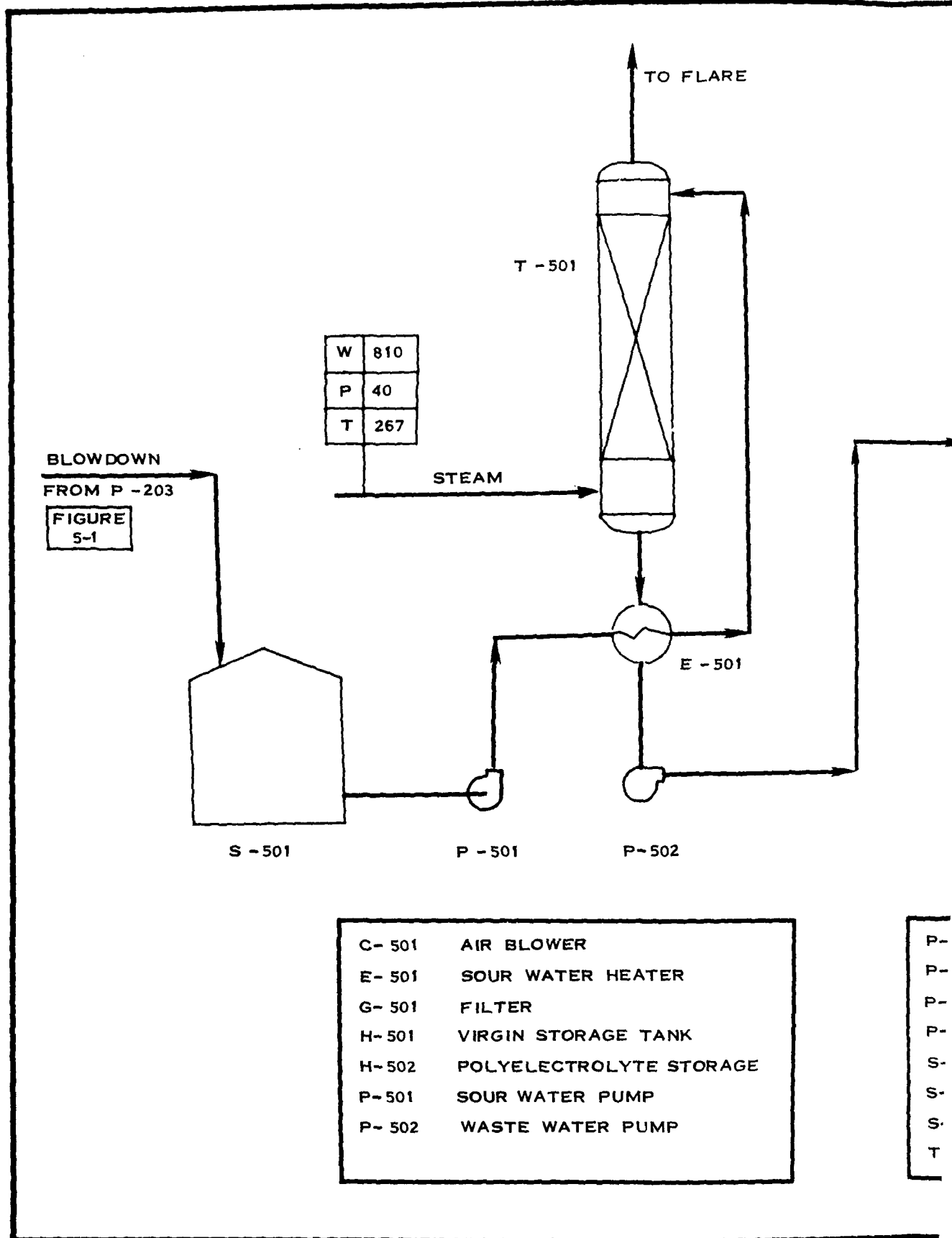
COAL GAS / FUEL CELL / COGENERATION

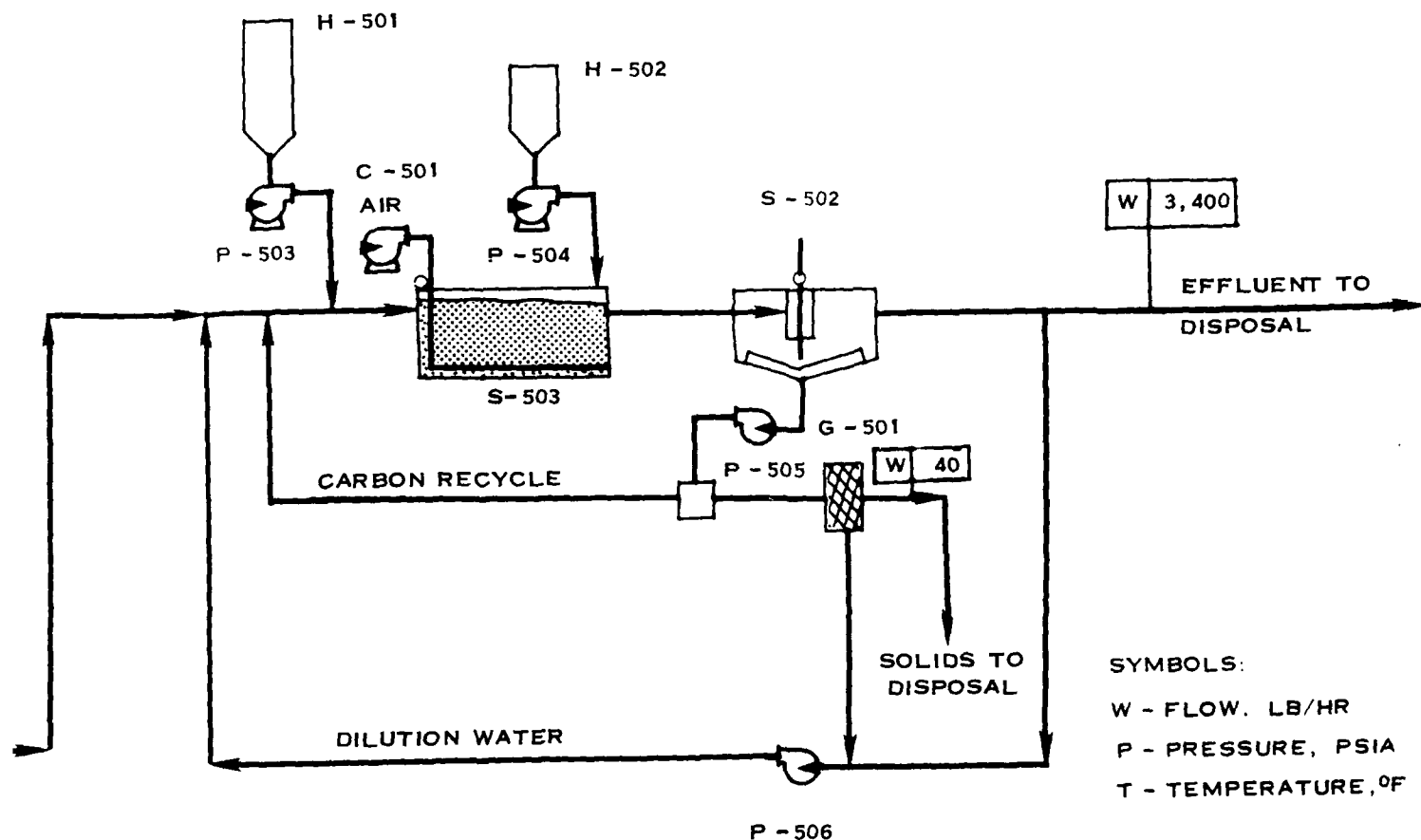
PROCESS FLOW DIAGRAM

SULFUR REMOVAL AND  
RECOVERY SECTION

FIGURE 5-3

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P- 503	VIRGIN CARBON FEED PUMP
P- 504	POLYELECTROLYTE STORAGE
P- 505	CARBON RECYCLE PUMP
P- 506	RECYCLE WATER PUMP
S- 501	SOUR WATER STORAGE
S- 502	SETTLING TANK
S- 503	AERATION CONTACT TANK
T- 501	AMMONIA STRIPPER

1/29/1985

DOA / GEORGETOWN UNIVERSITY  
COAL GAS / FUEL CELL / COGENERATION

PROCESS FLOW DIAGRAM  
PROCESS CONDENSATE  
TREATMENT SECTION

FIGURE 5-4

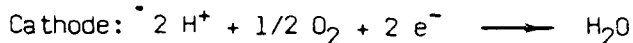
EBASCO SERVICES INCORPORATED

## 6.0 FUEL CELL SYSTEM

### 6.1 Introduction

A fuel cell is a device which converts the chemical energy of a fuel into electricity by electrochemical means. The basic components of a cell include two electrodes separated by an electrolyte. Fuel is continuously pumped over one electrode where it reacts electrochemically to give up electrons to an oxidant that is being pumped over the other electrode. The electrochemical conversion is similar to that of a battery except that fuel is not stored in the device, and it will produce electricity continuously as long as fuel and oxidant are pumped into it.

In theory, any oxidation/reduction reaction that produces a significant cell potential could be a candidate for fuel cell application. For practical reasons all developmental work in fuel cells has so far utilized the reaction of hydrogen and oxygen. The following reactions take place.



The electrolyte separating the electrodes serves as a medium for ion migration to allow for mass balance within the cell. Fuel cells are typed by the kind of electrolyte they use since this will determine their performance and applications. For an Electric Power Plant, the fuel cell considered in this study uses phosphoric acid as the electrolyte.

A typical phosphoric acid fuel cell is shown in Figure 6-1. The fuel is a hydrogen rich gas which is pumped through the anode side of the cell where oxidation takes place and electrons are released. The hydrogen ions produced at the anode migrate through a porous fiber matrix filled with phosphoric acid to the cathode where a reduction reaction produces water. Both anode and cathode are typically porous carbon coated with a platinum catalyst. Externally connecting the electrodes produce a dc current. For power applications the dc current is converted to ac by an inverter.

A single cell produces less than one volt potential but high current density, hundreds of amperes per square foot of electrode surface. The cells are in the form of thin sheets, and to get useful voltages, thousands of cells are connected in series. These cell stacks are the modular unit of the fuel cell power plant.

Unlike heat engines, the fuel cell produces electricity in an isothermal electrochemical reaction, and is thus not bound by Carnot cycle efficiency limits. Theoretically, voltages of 1.23 volts and cell efficiencies greater than 80% could be achieved with a phosphoric acid fuel cell; however, practical considerations require a cell designed for high current density which results in internal losses and polarization. Also, corrosion of the metal starts to become a problem at high voltages. For these reasons the effective cell limits are about .8 volt and 65% electrical conversion efficiency. The overall plant efficiency is lower due to the energy requirements of the fuel processing sections, but it still compares favorably to steam cycles especially considering the small plant size (7-11 MWe) and the low temperature 400°F.

The net or lower heat of combustion for hydrogen at 400°F is 104,800 btu/lb mole. Only about 55% of this energy is converted to electricity, with the remainder being rejected as heat. Thus, cooling for the cell is required.

## 6.2 Commercial Development

Table 6-1 indicates the various fuel cells and their development stage. Early development of fuel cells concentrated on rather exotic applications for NASA and the military. The Gemini and Apollo space missions inaugurated the use of fuel cells in space, and this use is continued today with the space shuttle Columbia. These cells used either alkaline or solid polymer electrolyte; and while they are extremely efficient, they require pure hydrogen and oxygen fuel. Their cost and intolerance to diluents such as CO<sub>2</sub> make them unsuitable for power plants.

The Department of Defense has been experimenting with phosphoric acid fuel cells for more than 25 years. This program continued today with testing of fuel cells to replace the Army's standard 1.5-5 kw field generators. Prototype cells are now being delivered but full application is hindered by the fact that the intended fuel, methanol, is not in the Army inventory. These fuel cells have unique specifications which are not applicable to power plants, but the program has contributed to the development of phosphoric acid cell technology.

The Gas Research Institute has been sponsoring research in small packaged fuel cells since 1958. This program has as its goal to develop phosphoric acid fuel cells, fueled by natural gas, that can be used as dispersed on site cogenerators for business or light industry. Numerous 12.5 kw cells were installed in the early 1970's and this has been followed by an ongoing program to install forty-five 40 kw cells throughout the United States. The first 40 kw cells were installed in 1982 and the program appears to be a technical success. Plans have been made to increase the size to 100 kw or larger. These cells are too small for central power plants, but much of the technology and laboratory test data is applicable for larger plants. This program has accumulated over 100,000 hours of fuel cell operation.

The characteristics of the phosphoric acid fuel cell are clearly compatible with large central station power plants. In 1972, United Technologies Corporation (UTC) who had been involved in the previous fuel cell programs, formed a venture with several utilities to develop a phosphoric acid power plant. The FCG-1 program tested a 1 MWe cell stack in 1977.

With EPRI and DOE assistance, the FCG-1 program was expanded to include the design and installation of a 4.5 MWe demonstration fuel cell located in downtown New York City with Con Edison as host utility. This fuel cell plant would use phosphoric acid cells, and naphtha or natural gas as the fuel. The cells would operate at 375°F and 50 psia resulting in cell voltages around .6 volt and a net heat rate of 9300 BTU/kw-hr. The power plant is described in reference 6-1.

Planned startup in 1981 of the demonstration cell was delayed more than three years, first by difficulties with local government agencies and then with mechanical problems in the fuel processing section. These problems were overcome, and in 1984 after operation of all subsystems, the fuel cell stacks were brought on line, but voltage output fluctuated widely. The cells in the stacks are extremely thin (less than 20 mils) and this presents a problem of electrolyte continuity. Should the phosphoric acid leak or evaporate the dried area ceases to work and may allow cross cell leakage. The 4.5 MWe demonstration cells had been in storage more than 6 years and apparently suffered irreversible electrolyte leakage. EPRI has announced that cell replacement will not be undertaken and it appears the power plant will never operate.

In 1979 Tokyo Electric Power Company (TEPCO) also purchased a 4.5 MWe demonstration cell from UTC. Although similar in design, this project did not experience the delays of the Con Ed Plant, and in 1984 attained full power. The plant is now in its first endurance test phase, and while minor mechanical problems have been encountered, the cells are operating as expected. The cells used in this plant were an improved version over the Con Ed cells, in that they contained what is referred to as a ribbed substrate. In addition to improving performance, this new substrate makes the cells more resistant to the phosphoric acid leakage problem.

UTC has now put forth the design of its modular prototype for the first generation of commercial plants (Ref. 6-2). It is an 11 MWe plant that contains numerous improvements over the 4.5 MWe demonstration plant. In addition to the improved substrate discussed above, the cell pressure and temperature have been raised to 120 psia and 400°F. This has raised cell voltage which is a measure of efficiency to around .7 volts. Projected heat rate for the plant is 8300 BTU/kw hr.

The phosphoric acid fuel cell is on the verge of commercialization. UTC is now actively trying to market its 11 MWe prototype plant. The original schedule called for 3 plants to be contracted for in 1982 with start-up and full commercialization in 1984. This schedule has not been met since no utility has announced a purchase.



Concurrent with UTC's development work, Westinghouse Electric Corporation has also had a phosphoric acid fuel cell power plant commercialization program. They have been conducting stack tests since 1981 and have developed a modular 7.5 MWe prototype power plant design (Ref. 6.3). Their schedule calls for two prototype plants to begin operation in 1986-87, but this may be optimistic since they have not received firm utility commitments.

Both UTC and Westinghouse have constructed facilities to manufacture the phosphoric acid cells. They have not yet invested in full mass production equipment. As a result the first cells are being manufactured by slower, more costly methods. Both companies are assessing the potential market in order to decide the timing of further production line investment. Because of this and the need to recoup certain R&D costs, the cell manufacturers have put a higher price tag on the first prototype cells. What future production line capacity will be is unknown at this time, but the vendors are assumed to presently have the capability to manufacture a minimum of 1-2 full size fuel cell plants per year.

Fuji Electric Company and Mitsubishi Electric Company of Japan also have an active fuel cell development program which calls for a 1 MWe pilot plant to begin operation in 1986. They have not yet released any designs or plans for a commercial plant.

In addition to the phosphoric acid fuel cell which is near commercialization, two other fuel cells are under development that show promise for power plant application. These are the molten carbonate and the high temperature solid oxide fuel cells. These cells will be more efficient, run at higher temperature and can theoretically reform hydrocarbon fuels directly in the cell thereby eliminating much of the fuel processing section. The molten carbonate cell is particularly suited for integration with a coal gasification plant because it will utilize any CO in the gas stream thereby eliminating the need for CO shift, and the higher temperatures make it easier for thermal integration with the gasifier.

These cells are second generation technology with expected commercialization in the middle to late 1990's. The molten carbonate cell is being developed by UTC and GE, and it undergoing stack tests. The solid oxide is being developed by Westinghouse and is still in the individual cell testing phase.

### 6.3 Design Criteria

#### 6.3.1 Fuel Cell

The fuel cell shall be a phosphoric acid electrolyte type sized for a single module of the commercial plant design of either UTC or Westinghouse as specified in references 6-2 and 6-3. The cell shall have a gross dc output of either 11.6 MWe or 7.5 MWe depending on the manufacturer. This type of fuel cell was chosen because of its suitability for the intended service and because it is near commercialization in its development.

The fuel cell shall convert the hydrogen rich coal gas to dc electricity at a minimum hydrogen conversion efficiency of 53% based on a nominal gas stream of 35% hydrogen. The oxidant shall be provided by pressurized air. Reject heat shall be utilized for either process or export steam needs. The heating value of hydrocarbons such as methane and unreacted hydrogen that passes through the cell will also be recovered.

It is recognized that the voltage and hence efficiency of the cell stacks will degrade with use. The cell stacks and the replacement schedule shall be designed to meet or exceed the specified voltage averaged over their lifetime. Stack replacement may be on a staggered schedule such that a mix of old and new stacks produces a smaller voltage fluctuation range. Stack lifetime shall be a minimum of 40,000 hours (4.57 years).

Except for cold startup, the fuel cell system shall be designed for automatic unattended operation.

### 6.3.2 Anode Gas

The fuel cell performance is highly dependent on the characteristics of the hydrogen rich fuel. Pressure, temperature and the percent hydrogen in the anode gas stream will affect both the cell voltage and current density. The cell manufacturers have designed their cells to operate at specific pressures and temperatures, and the gas feed and cell cooling shall maintain these parameters.

Impurities in the anode gas can poison the cell causing degradation faster than the design lifetime. While the effect of some impurities are known, there are still uncertainties in this area. Table 6-2 summarizes the effects of various components and impurities on the cell. The manufacturers have done some long term tests on the fuel cell, but no data is available from them specifically on coal gas. EPRI is funding Lawrence Livermore Laboratory to conduct a series of laboratory scale tests using a variety of impurities which would cover the range of components found in gasified coal.

The anode gas shall have the composition as specified in Table 6-3. This specification was derived from information obtained from cell manufacturers and preliminary results of tests at Lawrence Livermore. Since both cell manufacturers use the same type of catalyst, the effect of impurities should be similar. The higher temperature of UTC cell should make it slightly more resistant to poisoning.

### 6.3.3 Cell Cooling

Heat must be removed from the fuel cell stacks to maintain the design temperature of the cell. By vendor design, the coolant for the UTC cell is water and for the Westinghouse cell it is air.

Cooling water specifications are reported for the UTC cell in reference 6-4, however, experience by the Japanese indicates that cleaner water is required to prevent fouling and corrosion. TEPCO has issued very stringent water quality standards that require conductivity of less than .4 umho. These standards would be very difficult to achieve in a

cogeneration mode and the need for such stringent conditions is not clear. Design water quality standards shall be as indicated in Table 6-4.

For the Westinghouse cell, cooling shall be by oil free compressed ambient air.

#### 6.3.4 Environmental

The fuel cell power plant shall meet or exceed all appropriate federal and local standards for emissions. The base design shall meet all federal emission standards for coal fired central station power plants, with local standards also being imposed at the four specific sites.

Due to the need for gas cleanup to prevent catalyst degradation and the low reaction temperature, the fuel cell emissions are well below Federal EPA standards. Table 6-5 gives the design emissions for the base fuel cell design. Actual emissions will vary slightly depending on the coal.

Noise standard shall be 55 db at 100 feet per UTC specification.

Water usage shall be a minimum, and makeup water shall be primarily for losses in cogeneration. It is expected that any local regulation on thermal discharges shall be met.

The fuel cell has a small footprint and a low profile. It is not anticipated that there will be any local objection due to land use or aesthetics. The fuel cell can be located indoors or outdoors, however, in extremely cold climates a weather enclosure may be necessary.

#### 6.3.5 Flexibility

The ratio of steam to electricity is dependent upon the design of the thermal management system. Any flexibility in the ratio cannot come from the fuel cell since the ratio of heat rejected per kilowatt produced is roughly constant. The fuel cell shall, however, be capable of operating

from 50% to 100% of rated power with little effect on efficiency. It is anticipated that the fuel cell will be run continuously at its full rated power.

#### 6.4 System Description

The fuel cell system as shown in Figure 7-1 includes the fuel cell stacks, exhaust gas combustor and cathode gas compressor. The plant is sized for one fuel cell module of the present commercial vendors.

The generic base design includes an 11.6 MWe UTC fuel cell and is described in Section 6.4.1. An alternate design includes a 7.5 MWe Westinghouse fuel cell and is described in Section 6.4.2.

Two site specific designs will incorporate the UTC cell and two site specific designs will incorporate the Westinghouse cell. Site specific conditions will not change any of the fuel cell system hardware except for the possible need for weather enclosures. The fuel cell system operating parameters and heat balance will vary slightly between any two sites with the same cell because the different coal types will cause the anode gas composition and heating value to vary.

##### 6.4.1 UTC Fuel Cell System

The UTC fuel cell stack consists of alternating layers of ribbed cell substrates, separator plates and cooling channels. The cells along with manifolds for anode gas, air and coolant are all enclosed in a pressure vessel. Figure 6-2 shows a typical fuel cell stack. Eighteen (18) stacks mounted above prefabricated piping make up one 11.6 MWe fuel cell. Arrangement and performance data is shown in Table 6-6.

The UTC fuel cell is designed to operate at 405°F and 120 psia with an average cell voltage of .68 volts. To produce the design power the system requires 775 lb moles/hr of hydrogen.

Referring to Figure 7-1, The hydrogen rich gas from the gasifier section is pumped into the anode of the fuel cell and compressed air is directed to the cathode. The fuel cell produces under design conditions 11.6 MWe

of dc power (gross) which is sent to the Power Conditioning System. The reaction in the cell also produces about  $28 \times 10^6$  BTU/hr of heat which is rejected to the cooling system. Cooling water is circulated through the cell to maintain the design temperature. Partial boiling of the water takes place in the cell and the steam/water mixture is returned to the Thermal Management System where the heat is recovered as process or export steam.

Approximately 15% of the hydrogen passes through the cell unreacted along with hydrocarbons such as methane. The heating value of these gases are recovered by combining the anode and cathode exhaust streams and reacting in a catalytic combustor. The heat of reaction releases approximately  $29 \times 10^6$  BTU/hr. A catalytic combustor was chosen because this reacts gases even in trace quantities. The combined stream contains only 2.5% hydrogen which is below the flammability limit of 4%. For a burner type combustor additional natural gas would have to be added to maintain the flame.

The hot exit gases from the combustor go to an expansion turbine where energy is extracted to drive the cathode gas air compressor. An additional 2.5 MWe net power is extracted from the motor generator and the exhaust gases and are directed to the Thermal Management System where additional heat is recovered.

#### 6.4.2 Westinghouse Fuel Cell System

The Westinghouse fuel cell stack consists of multiple layers of thin cells with gas channels in the layers. Fuel gas, process air (oxidant) and cooling air all circulate through the channels. The reactants form a counterflow pattern resembling a "Z" and Westinghouse refers to their cell as the Z-Bi-Polar Stack. The cells are cooled by compressed air which also serves as process air for the cathode. Twenty (20) stacks mounted above prefabricated piping make up one 7.5 MWe fuel cell. Figure 6-3 shows a typical fuel cell stack. Arrangement and performance data is shown in Table 6-6.

The Westinghouse fuel cell is designed to operate at 375°F and 70 psia. To produce the design power the system requires 556 moles/hr of hydrogen.

In addition to being of smaller size, the Westinghouse system will deviate from the base design because it is air cooled. Figure 6.4 shows a partial flow diagram utilizing the Westinghouse cell. Gas from the gasifier section is directed to the anode while compressed air diverted from circulated coolant is directed to the anode. Under design conditions the reaction produces 7.5 MWe of dc power (gross) plus about  $21 \times 10^6$  BTU/hr of reject heat for process or cogeneration. Cooling air is driven by an air circulator, with the coolant loop designed for minimum pressure drop to reduce the required horsepower. Make up air to balance the cathode stream is provided by a compressor.

Approximately 17% of the hydrogen passes through the cell unreacted along with methane and other hydrocarbons. The anode and cathode streams are combined and the heating value of the fuel is recovered in a catalytic combustor. As discussed in Section 6.4.1, a catalytic combustor was chosen because the hydrogen in the fuel is less than the flammability limit. The hot exit gases are directed to the Thermal Management System where the heat energy is extracted before release to the stack.

#### 6.5 Technical Risks

The technical risks associated with the Fuel Cell System involve the fuel cell itself and the catalytic combustor.

The risks associated with the fuel cell involve failure to perform as specified due to:

- electrolyte leakage
- catalyst poisoning
- initial low cell voltage or voltage fluctuations
- coolant fouling (UTC)

Each of these failures is possible but the risks appear manageable. As noted the fuel cell installed at Con Ed failed due to electrolyte leakage, however, UTC has improved their cell since then. After the failure, UTC retrieved a test cell used at TVA but which had been in storage for 3 years. This was an improved ribbed substrate, and no leakage was evident upon operation.

As noted in the text, the catalyst is poisoned by many species found in coal gas. Poisoning could reduce the design life of the cell to less than 40,000 hours. Although demonstration cells have not run on coal gas, on-going research at Lawrence Livermore should more precisely define this risk. The approach to reduce this risk is to use state-of-the-art clean-up systems in the gas processing section.

Low cell voltage or voltage fluctuation would indicate a defect in the manufacture. A rigorous testing and QC program for the cell stacks would minimize this risk.

Coolant fouling can be minimized by the design and operation of the water treatment system. More data will also be available from the continued operation of the TEPCO plant.

If fuel cells are to be utilized they must be purchased from one of the two existing vendors. The assessment of risk ultimately comes to an assessment of the vendors' development and testing program to date, and whether the fuel cell is ready for commercialization. At this point the risk also must be judged less for UTC due primarily to the fact that they have an operating 4.5 MWe demonstration plant.

The other technical risk is with the catalytic combustor. These items have never been used for precisely this application, although an extensive amount of data exists for their use on automotive emissions. Since they operate at higher temperature, their catalyst should be more poison resistant than that of the fuel cell. Since they are not a high dollar item, they also can be replaced with a natural gas flame burner.

#### 6.6 References

- 6-1 United Technologies Corp., "4.8 MW Demonstration Power Plant, Final Report" FCR-3278 December 1981.
- 6-2 United Technologies Corp., "Description of a Generic 11 MW Fuel Cell Power Plant for Utility Applications". EPRI EM-3161, September 1983.



- 6-3 Westinghouse Electric Corp., "Phosphoric Acid Fuel Cell 7.5 MWe  
dc Electric Power Plant Conceptual Design", WAESD TR-83-1002,  
May 1983.
- 6.4 Kinetics Technology International Corporation, "Site Specific  
Assessment of a 150 MW Coal Gasification Fuel Cell Power Plant",  
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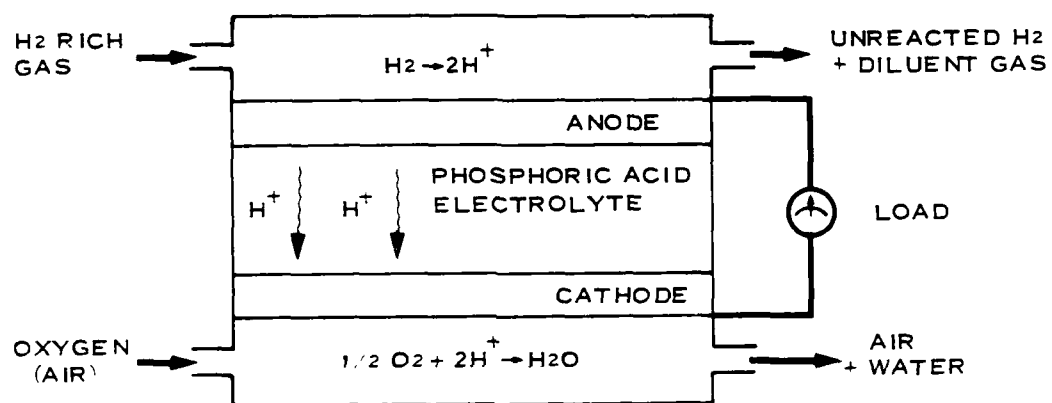


FIGURE 6.1 TYPICAL PHOSPHORIC ACID FUEL CELL

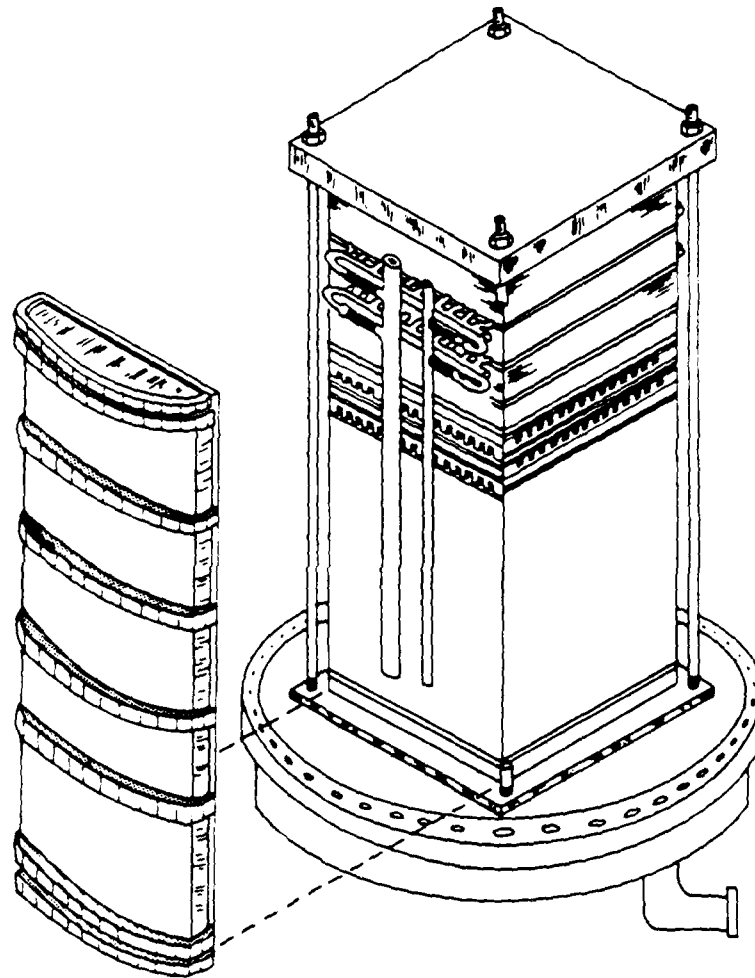


FIGURE 6 -2 TYPICAL UTC CELL STACK

# FUEL CELL MODULE

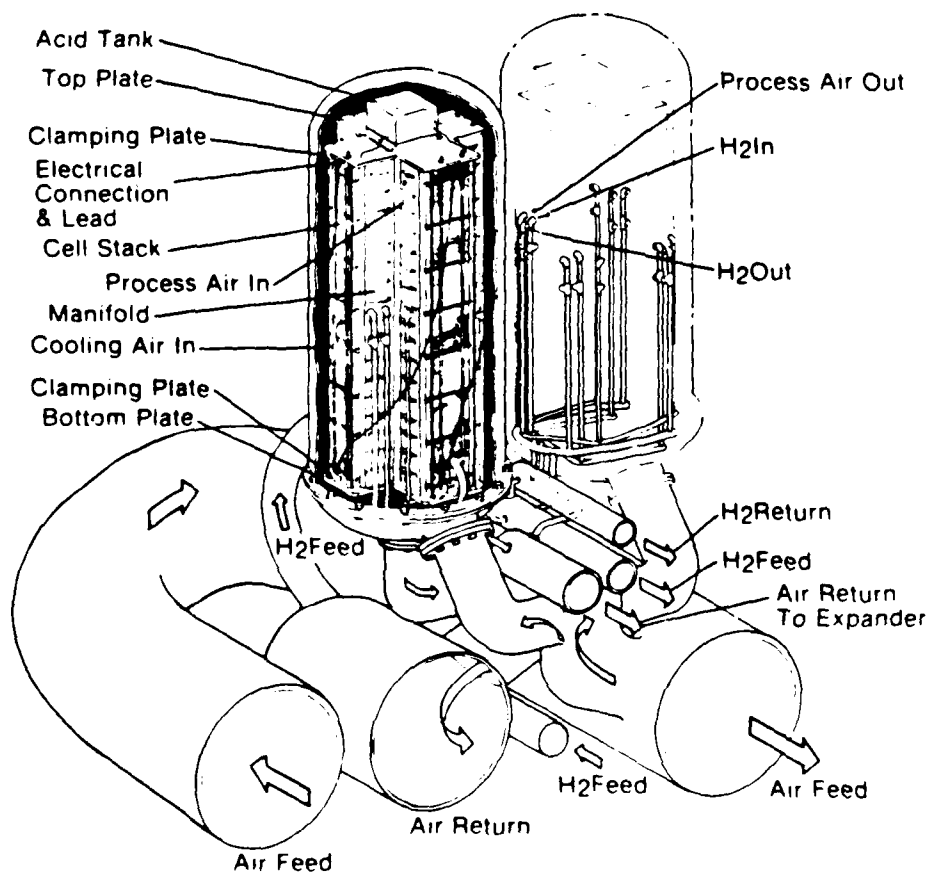


FIGURE 6-3 WESTINGHOUSE FUEL CELL MODULE

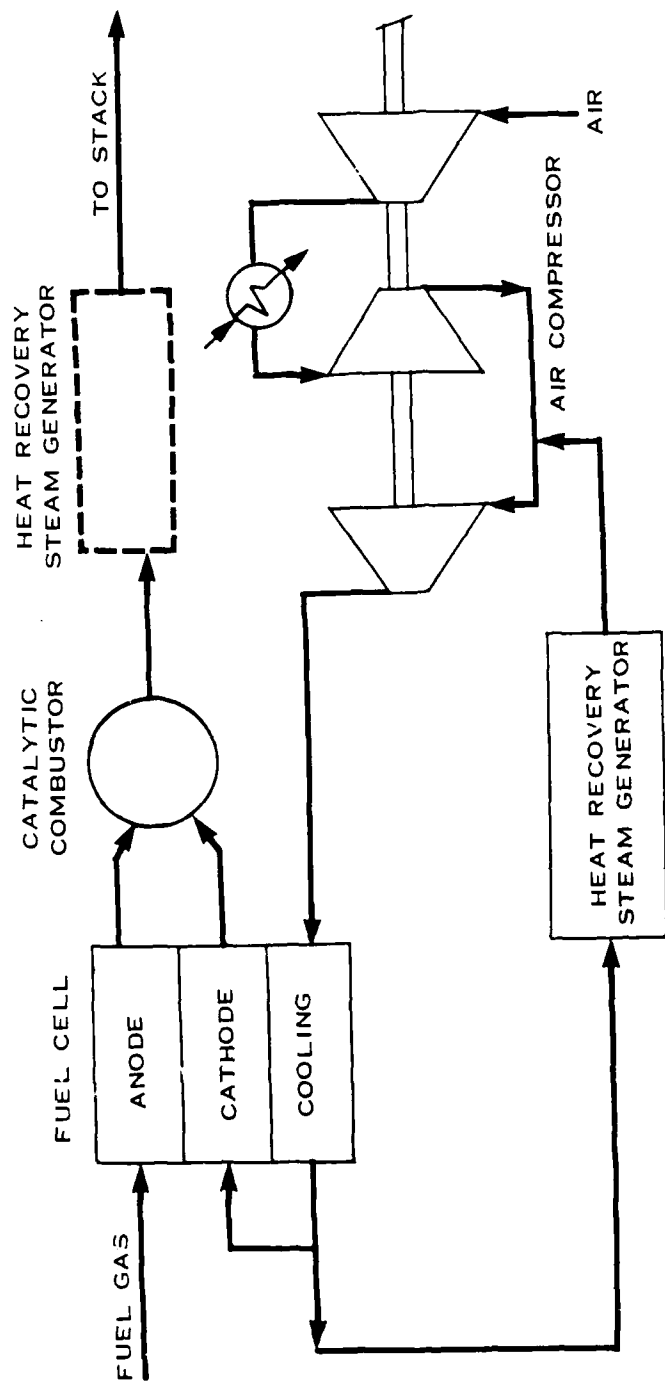


FIGURE 6- 4 WESTINGTON FUEL CELL FLOW DIAGRAM

TABLE 6-1  
FUEL CELL TYPES

<u>Type</u>	<u>Temperature</u>	<u>Efficiency*</u>	<u>Applications</u>	<u>Commercialization</u>
Phosphoric Acid	400°F	40%	Power Plants On Site Cogen Industrial Cogen Transportation	1986
Molten Carbonate	1200°F	55%	Power Plants Industrial Cogen	1994
High Temperature Solid Oxide	1800°F	45%	Power Plants Industrial Cogen	1998
Alkaline	200°F	70%	Space & Military	present
Solid Polymer	150°F	70%	Space & Military	present

\*Efficiency refers to conversion of heating value of the primary fuel to electricity without regard to cogeneration.

TABLE 6-2

EFFECT OF ANODE GAS COMPOSITION

<u>COMPONENT/PARAMETER</u>	<u>EFFECT ON FUEL CELL</u>
Min H <sub>2</sub> %	Cell efficiency, drop of approx. 0.6 mv cell voltage for each 1% less H <sub>2</sub> than design, also large drop if ratio H <sub>2</sub> /CO gets too low
CO	Causes reversible polarization of anode by itself, and acts in combination with H <sub>2</sub> S to poison anode
COS	Causes irreversible polarization of the cell
H <sub>2</sub> S	Forms COS in presence of CO and catalyst. See COS above
NH <sub>3</sub>	Neutralizes the phosphoric acid
Olefins	Poisons catalyst; ethylene oxidizes at high Temperature and is not a severe problem, but higher weight olefins can be a problem
Higher Hydrocarbons	Speculative poison effect, but test data shows catalyst relatively insensitive
Cl <sub>2</sub>	Corrosion
Tars/Oils	Coat and poison catalyst and block porous media
Metal Ions	Decrease catalyst activity
Particulates	Block porous media of cell

TABLE 6-2 (Cont'd)

<u>COMPONENT/PARAMETER</u>	<u>EFFECT ON FUEL CELL</u>
Temperature	Phosphoric cells can operate in range of 150°F to 450°F. Higher temperature increases voltage, catalyst activity and makes cell less sensitive to sulfur poisoning. Higher temperature, however, will also increase corrosion, catalyst sintering and $H_3PO_4$ loss
Pressure	Increase pressure will increase the current density and voltage; decrease cell size and cost



TABLE 6-3  
ANODE FEED GAS SPECIFICATION

<u>COMPONENT</u>	<u>LIMIT</u> <sup>(1)</sup>
H <sub>2</sub>	35% min <sup>(3)</sup>
CO	2% max (dry basis)
Olefins	1000 ppm max
Higher Hydrocarbons	1000 ppm max
NH <sub>3</sub>	0.5 ppm max
Cl <sub>2</sub>	0.5 ppm max
H <sub>2</sub> S + COS	4 ppm max
Tars/Oils	.05 ppm (by wt) max
Metal ions	1 ppm max (by wt)
Particulates	30 ug/m <sup>3</sup> max

	<u>UTC</u>	<u>WESTINGHOUSE</u>
Pressure	120 psia	70 psia
Temperature <sup>(2)</sup>	405°F	375°F
H <sub>2</sub> Flow	775 lb moles/hr	556 lb moles/hr

Notes:

- (1) By volume unless otherwise noted
- (2) Design temperature of cell. Inlet temperature of coolant is less depending on cell cooling system design.
- (3) Design basis. Lower values may be acceptable but will penalize cell performance (See Table 6-2).

TABLE 6-4

FUEL CELL COOLING WATER CRITERIA

<u>Parameter</u>	<u>Limit</u>
Suspended Solids	1 ppm
SiO <sub>2</sub>	0.3 ppm
CO <sub>2</sub>	450 ppm
pH	5.0 - 7.0
Conductivity	10 micromho/cm

TABLE 6-5

FUEL CELL EMISSIONS

<u>POLLUTANT</u>	<u>BASE DESIGN*</u> <u>(lbs/million BTU)</u>	<u>EPA STANDARD**</u> <u>(lbs/million BTU)</u>
NO <sub>x</sub>	.035	0.7
SO <sub>x</sub>	.0015	1.2
TSP (Particulates)	.0011	0.1
Smoke	Neg.	20% Opacity

\* does not includes any direct emissions from coal gasification system or any auxiliary boilers

\*\* for coal fired power plants

TABLE 6-6

FUEL CELL PARAMETERS  
BASED ON TYPICAL COAL GAS OF 35% H<sub>2</sub>

<u>Parameter</u>	<u>UTC Fuel Cell</u>	<u>Westinghouse Fuel Cell</u>
No. of Fuel Cell Stacks	18	20
Stack Size	5' 10" dia x 10' 10"	4' 6" dia x 11' 6"
Overall skid ht. (Fuel Cell Skid Only)	16'	25' 2"
Arrangement	3 linear groups of 6 stacks, 3 stacks per skid	2 groups of 10 cell stacks arranged in 2 rows of 5 vessels each. Mounted on an elevated platform with piping below
Cell Voltage (DC)	.68V	.66V
Line Voltage (DC)	2100V	1070V
Power Output (gross DC)	11.6MWe	7.5MWe
Cell Operating Temp/pres	405°F/120 psia	375°F/70 psia
Typical Stack Life	40,000 hours	40,000 hours
Fuel (Anode) Input (H <sub>2</sub> )	775 lb moles/hr	556 lb moles/hr
Anode Mass Flow Inlet	55,000 lbs/hr	36,000 lbs/hr
Anode Inlet Temp	405°F	375°F
Anode Inlet Pressure	120 psia	76 psia
Anode Exhaust Temp/Pres	405°F/115 psia	375°/66 psia
H <sub>2</sub> Utilization	85%	83%
Cathode Inlet Flow	500 lb moles O <sub>2</sub> /hr 70,000 lbs air/hr	461 lb moles O <sub>2</sub> /hr 63,800 lbs air/hr
Cathode Inlet Temp/Pres	361°F/118 psia	same as coolant outlet
Cathode Outlet Temp/Pres	405°F/115 psia	378°F/69 psia

TABLE 6-6 (Cont'd)

<u>Parameter</u>	<u>UTC Fuel Cell</u>	<u>Westinghouse Fuel Cell</u>
O <sub>2</sub> utilization	70%	50%
Coolant type	water/steam	air
Coolant flow	$1.67 \times 10^5$ lbs/hr	$1.3 \times 10^6$ lbs/hr
Inlet Temp/Pres	371°F/250 psia	297°F/71 psia
Outlet Temp/Pres	397°F/240 psia (2 phase)	365°F/70 psia
Heat rejected to coolant	$28.7 \times 10^6$ BTU/hr	$21.5 \times 10^6$ BTU/hr

## 7.0 THERMAL MANAGEMENT SYSTEM

### 7.1 Introduction

The Thermal Management System (TMS) receives heat o. byproduct fuel (e.g., tars and oils) from various sources within the GFC System and processes it as follows:

1. Converts heat to a condition suitable for reuse in the GFC facility.

Example would be the CO shift process, freeze protection, etc.

2. Converts heat to a condition suitable for export as steam, hot water or glycol.
3. Converts heat to power.
4. Rejects low level heat to the environment.

After satisfying the process heat requirements of Item 1 above, the remainder of available heat (excluding Item 4) can be apportioned in different ways between export heat (Item 2) and power generation (Item 3) by selecting the appropriate TMS design.

The base system design which is referenced to the Washington, DC site, favors production of export heat. This approach which tends to reduce capital costs compared to one favoring export power will be economically analyzed in a later phase of this study. Capital costs are reduced due to the elimination of a turbine/generator, steam condenser and associated reduction of cooling system capacity. Also, the Heat Recovery Steam Generator (HRSG) is rated for a lower pressure and does not require a superheater section.

The base design of TMS includes the following major components:

Fuel cell steam separator  
Fuel cell circulating pumps

Heat recovery steam generator  
Deaerator and feedwater pumps  
Water treatment  
Condensate storage tank  
Liquid/air coolers

In addition to the above, are the piping, wiring, controls and accessories required for a complete installation.

The base design of TMS receives heat from two sources for processing:

1. the fuel cell cooling system
2. exhaust gas of the combustor/expander which is fed by the fuel cell anode and cathode vent gases.

## 7.2 Fuel Cell Cooling System

Referring to Figure 7-1, fuel cell cooling water is pumped from the steam separator and after mixing with deaerated feedwater, enters the UTC fuel cell at 371 and 250 psia where it absorbs approximately  $29 \times 10^6$  Btu/hr of heat from the electrochemical reaction. The cooling water must maintain fuel cell temperature at the vendor's specified design of 405 F.

Following a pressure drop of 10 psi through the fuel cell, water and steam exits at 397 F. Approximately 29,000 lb/hr of the coolant flow appears as 240 psia saturated steam in the steam separator (This steam condition is fixed by the required UTC fuel cell temperature). In the Washington, D.C. system, 20,000 lb/hr of this steam will be piped underground (with condensate return) to the gas processing location where the major part of it will be used in the CO shift process. The remainder will be reduced in pressure to 90 psia for use as export steam. The steam pressure of 240 psia allows a margin for pressure loss in the connecting pipe and for pressure drop across the process control valves, sufficient for stable control.

### 7.3 Heat Recovery Steam Generator and Auxiliaries

In the base design, all expander heat is dedicated to the generation of steam for export and for feedwater heating. Transfer of heat from the expander exhaust takes place in the heat recovery steam generator (HRSG) which contains a feedwater heating section and an evaporator.

Expander exhaust gas enters the HRSG at 664°F. For maximum heat recovery, the exit temperature of the exhaust should be as low as possible but to prevent gas side acid corrosion, should not be lower than the dewpoint temperature. In this preliminary evaluation of HRSG capacity, an exit temperature of 250°F was assumed and will be confirmed later in terms of specific information on vent gas combustion products. Also to be considered are correct sizing of the HRSG internals and correct gas velocities to assure that gas pressure drop is not greater than 10 inches wg to avoid reduction in expander capacity.

To maximize mass flow of steam (10,000 lb/hr), the lowest acceptable pressure (90 psia for the Washington, DC site) is generated in the HRSG.

A deaerating feedwater heater operating at 26 psia serves both the fuel cell cooling system and the HRSG. The HRSG provides a throttled steam connection to the deaerator from the 90 psia header.

A vented condensate tank with 8 hour storage capacity receives treated makeup water and condensate return from the gas process and from the export steam users.

The temperature of condensate as it is pumped from the condensate tank to the HRSG economizer section is expected to be low (110°F to 150°F), varying with the specifics of gas process design, makeup water temperature and export steam use.

This low condensate temperature, makes possible the efficient removal of heat in the economizer section by permitting a correspondingly low exiting exhaust gas temperature.



#### 7.4 Site Differences

A basic difference between the UTC (Washington D.C. and Fort Hood) and the Westinghouse (Scranton and Anchorage) fuel cells as it affects the Thermal Management System is that the Westinghouse fuel cell operates at a lower temperature and transfers its heat to cooling air which in turn transfers its heat to the steam cycle. Because of the intermediate heat exchange medium of air and also because air has poorer heat transfer properties, more total heat exchange surface is to be expected at a higher initial cost.

Because of the lower fuel cell operating temperature the steam generated from the Westinghouse fuel cell heat is limited to lower pressures - 70 psia or less which is too low for use in the CO shift process. To meet CO shift requirements, exhaust from the combustor/expander however, is used to generate steam in an HRSG at the higher pressures required, or for export process requirements.

Heat balances for each site will also vary due to differences in coal which affect CO shift steam flow and expander exhaust energy.

Low site ambient temperatures due to season and to geographic location will divert a greater amount of electrical and thermal energy to provide space heating of the facility enclosures, freeze protection, makeup water heating and heat losses to atmosphere. The risks associated with freeze damage can be minimized by use of proven freeze protection measures, correct cleaning and flushing procedures and glycol brine in external cooling piping.

#### 7.5 Flexibility of Operation and Options

One of the requirements of the UTC Fuel Cell is to maintain constant internal temperature through control of water pressure regardless of steam demand. For this purpose a backpressure steam valve will control the flow of steam independently of user's requirements, making user responsible for control of his standby heat source to make up any shortfall in thermal energy (Reliability and redundancy of this control to reduce risk of temperature damage to fuel cell will be reviewed).

This represents an inflexibility of the system which will be studied in terms of control arrangements. For similar reasons, this inflexibility applies as well to the Westinghouse fuel cell.

The converse of the above operating condition is where thermal load of the user drops below the heat output of the fuel cell system. To avoid the necessity to reduce output of the system, excess steam can be routed to and its energy extracted by a backpressure or condensing turbine driving a generator.

The need for this turbine will be dictated by site thermal load characteristics. If the second condition of steam supply being in excess of user's requirements is unlikely to occur or will occur infrequently, the capital cost of the turbine generator may not be justified. It will be noted that the base system design does not include this excess steam turbine generator.

The base system as shown has two steam pressure levels - 240 psia from the fuel cell and 90 psia from the HRSG.

If higher pressure of steam is required from the HRSG for summer operation of steam turbine driven centrifugal chillers, one HRSG can be supplied with the capability of operating at either the higher or lower pressure with appropriate changeover controls.

Another possibility is use of a motor driven open cycle heat pump (centrifugal compressor) which compresses the steam to the desired pressure. Although this type of equipment is compact, capital cost and energy consumption tends to be high for small installations and would require study.

A major option for augmenting thermal and electrical output is burning the oil and tar byproduct of gasification (approximately 2000 lb/hr) in a steam generator. High pressure superheated steam could then drive a backpressure turbine which exhausts to the steam distribution system. For additional power, the turbine can at a system cost increase, be of the condensing type with a smaller quantity of steam available for process or export from a turbine extraction point.

AD-A173 637

BASIC SYSTEM DESCRIPTION FOR COAL GAS/FUEL  
CELL/COGENERATION PROJECT(U) Ebasco SERVICES INC NEW  
YORK C TRAPP ET AL. 29 JAN 85 DARC29-85-C-0007

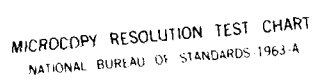
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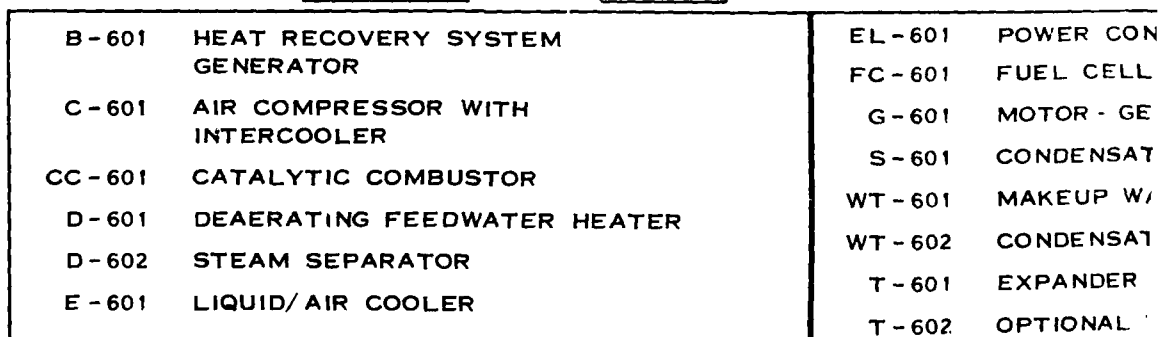
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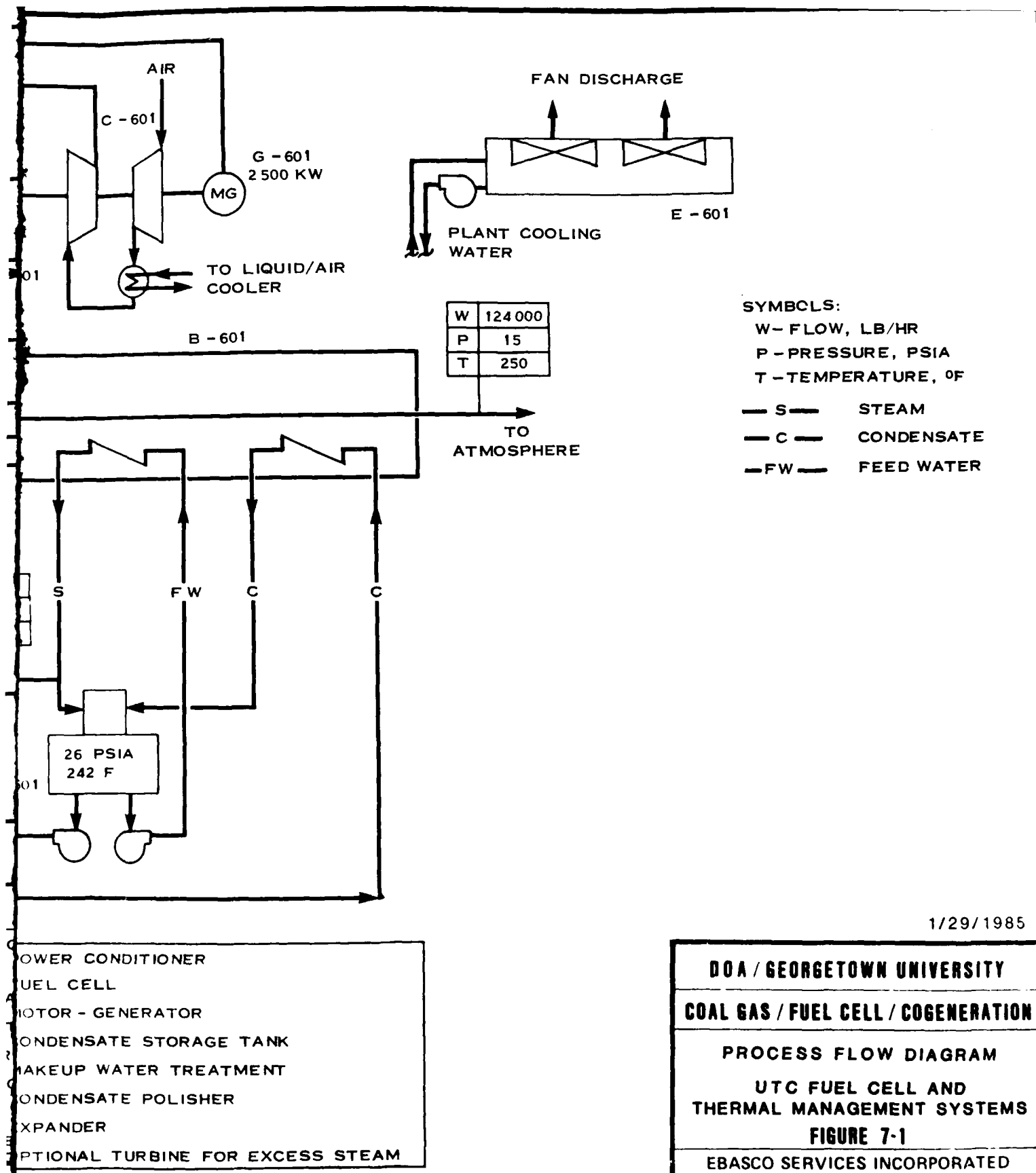
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Another option for either the UTC or Westinghouse system is to replace the expander which drives the air compressors with an electric motor drive. The catalytic combustor gas will then directly enter the HRSG at a temperature that is 500 to 800°F higher thereby generating more steam. This must be weighed against the value of lost fuel cell system net electrical capacity.





1/29/1985

## 8.0 POWER CONDITIONING SYSTEM

### 8.1 Background

Power conditioning is required to deliver fuel cell electric power into the AC power grid at appropriate interface conditions. The technology needed to accomplish this objective has been the subject of intense research in the last few years because of interest in MHD, solar photovoltaic, wind energy and battery energy storage, all of which produce DC power. The power conditioning circuitry developed for these applications however is not directly applicable to fuel cells because of low efficiency and inherent characteristics of the power source. Thus, commercial systems of the size range required for this project are not available at this time. In order to resolve this problem, the fuel cell manufacturers, Westinghouse and UTC, have undertaken programs to develop suitable power conditioning units. Both have selected designs which are adaptations of systems developed under the research programs mentioned above. Westinghouse and UTC are confident that these systems could be made available for this project.

### 8.2 Technology Evaluation and Selection

This section discusses the technology options available for power conditioning and the rationale stated by Westinghouse and UTC for selecting the systems they are offering.

#### 8.2.1 Commercialized Technologies

The key issues in power conditioning are the methods which are used to establish the AC wave form and assure that this wave is synchronized with the AC utility line. The latter issue is referred to as commutation and two options are available: line commutation by which the utility line itself is used as a reference signal to synchronize the conditioner output with the power grid; and forced or self commutation in which the conditioner contains an internal circuit which generates the reference signal. Historically, these systems have been developed for applications which require AC power where the system is either stand alone or grid connected.



Wind, battery and solar applications are usually much smaller than the 7.5-10.0 MWe size range required for this project but conditioner units of both types have been developed for these applications. Another technology base is the large high voltage units required for high voltage DC transmission lines which are line commutated.

Stand alone systems have been developed for space and military applications. Extensive research by NASA has resulted in a proven technology base which relies on pulse width modulation to produce the AC wave form. These systems are used with battery, solar and small fuel cell power sources.

The inherent voltage and current operating characteristics of the power sources require that special circuits be included in the conditioner system to allow the power source to behave as either a voltage or current source. Fuel cells have operating characteristics different than the other sources mentioned. Therefore unique circuitry has to be defined for this application. An additional design consideration is flexibility in that fuel cells are designed to operate from 25 to 100% power levels with quick response times.

UTC and Westinghouse have elected to offer systems based on the two most practical combinations of these design options; voltage sourced/line commutation (VSLC) (Westinghouse) and current sourced/forced commutation (CSFC) (UTC).

#### 8.2.2 United Technologies (UTC) (CSFC)

United Technologies Corporation has successfully applied CSFC technology to the 4.8 MWe prototypes systems installed at Consolidated Edison's New York City Facility and the TEPC Facility in Japan. In addition, UTC in conjunction with EPRI have successfully constructed and tested one pole of the inverter circuitry for their 11 MWe station. (Reference 8-1) This work was completed in 1982 and there is current interest in constructing the other poles and assembling and testing the entire converter system.

UTC's rationale for selecting this option is that SCI Technology allows:

- o Achievement of a unity power factor without requiring capacitors
- o Ability to supply leading or lagging VARS
- o Need for only small post inversion filters
- o Minimal harmonic interaction with power grid
- o Ability to operate in isolated mode
- o Potential for cost reduction due to improvements in solid state thyristor technology
- o Applicability to energy storage applications
- o Need for only conventional power output transformer

#### 8.2.3 Westinghouse (VSLC)

Westinghouse proposes to offer a VSLC converter which is a second generation adaptation of the 3.5 MWe system they installed in 1981 to the MHD test bed facility (CDIF) in Butte, Montana. (Reference 8-2) This system offers the following:

- o A proven technology base
- o Reliability of performance
- o Fault clearing capability
- o Ability to handle a wide range of DC voltages
- o Need for only non-inverter grade, low cost thyristors
- o Economic VAR regulation

#### 8.2.4 Alternate Concepts

Alternate commercial systems are not available which requires the selection of power conditioning units offered by the fuel cell manufacturers.

### 8.3 Technology Description

#### 8.3.1 UTC System

TABLE 8.1 UTC POWER CONDITIONER DESIGN CRITERIA

---

Gross Power in	11.6 MWe
Real Power	
Rated	11 MW net ac at sea level, up to 115°F Ambient
Minimum	0 MW net ac (STANDBY)
Operating Range	Continuous between 30% and 100% of rated power
Reactive Power	Up to 11 MVAR leading or lagging
Real Power Step Changes	
On Load	1 MW/sec. increase
From STANDBY	15 sec. to rated
From HOLD	15 to 60 min. to rated
Reactive Power Step Changes	
Minimum to Rated	0.2 second
Efficiency	95% at full power

#### 8.3.1.1 Design Criteria

The power conditioner is designed to deliver 60 Hz, three phase AC power to the power grid according to the conditions specified below in Table 8.1.

#### 8.3.1.2 System Components

The power conditioning system is comprised of the elements shown in Figure 8-1. A brief functional description of each element follows:

- o Electrical Protection Unit - This element is responsible for protecting the fuel cell stacks from high voltage open circuit conditions when the system is not producing power. It also provides protection against reverse currents and ground fault conditions.
- o Inverter Bridges - This is the key element in the system in that it converts the unregulated DC voltage into 3-phased AC modulated stepped wave voltage. Two 3-phase inverter bridges are provided and the bridges are configured as to allow cancellation up to the 11th harmonic.
- o Series Reactance - This element limits surges and controls real and reactive output and further helps reduce harmonics content in the output.
- o Output Transformer - The transformer is of a standard design sized to provide 11 MVA at 13,800V high side and 1450 volts low side.
- o Utility Interface - A circuit breaker, overcurrent sensor as well as lightning or surge protection is provided.
- o Control - An overall controller is provided which takes commands from the system site controller.

#### 8.3.1.3 Physical Arrangement

The entire power conditioner fits on one truck transportable pallet. Figure 8-2 shows the arrangement of the system. The footprint for the electrical system is approximately 80 ft by 40 ft.

#### 8.3.2 Westinghouse System

##### 8.3.2.1 Design Criteria

The power conditioner is designed to deliver 60 Hz three phase AC power to the utility grid according to the following criteria shown in Table 8.2.

##### 8.3.2.2 System Components

The Westinghouse power conditioning system is comprised of the elements shown in Figure 8-4. A functional description of each element is as follows:

- o Current Consolidation - In that the Westinghouse design consists of twenty fuel cell modules which connect into two summation points, it is essential that a system be provided which compensates for voltage differences at the modules terminal points. The current consolidation element performs this function.
- o DC/AC Conversion - The DC/AC converter adjusts the voltage at the summation point such that the DC/AC converter sees a fixed voltage.
- o DC/AC Converter - The output of the DC/AC converter is transformed into a sinusoidal waveshape by means of the thyristor bridge converter.

TABLE 8-2 WESTINGHOUSE POWER CONDITIONING DESIGN CRITERIA

Power Conversion

Rated Full Power Input	7.5 MWe DC
Rated Partial Power Input	25% of rated full power
Efficiency at Full Power	96%
Efficiency at Partial Power	92%

Power Factor                      Unity or leading at greater than 25% power.

Fault Protection

DC Power	Electronic circuit interruption
AC Power	Circuit breaker

Response Times                      Not to limit fluid system transient response times or result in spurious shutdowns.

- o AC Interface -The bridge outputs are fed into a special transformer which converts the fuel cell power into AC line voltage. Circuit breakers, surge and lightning protection are provided.
- o Controls - A preprogrammed central system controls the inverter into assuming any of several operating, startup, shutdown or standby conditions.

A complete description of the system is provided in Reference 8-4.

#### 8.3.2.3 Physical Arrangement

A typical physical arrangement is shown in Figure 8.4. The system consists of two units 10 ft wide by 18 ft long by 8 ft high.

#### 8.4 Siting Considerations

No unique siting problems or hardware modifications are perceived for the power conditioning unit.

#### 8.5 Technology Risks

Although both the Westinghouse and UTC systems are based on well established technology bases, neither system has been tested under the conditions encountered during fuel cell operation. All parties including EPRI are confident that both system can be shown to operate reliably in the time scale required. As was discussed earlier, no alternate commercial technology packages are available so that the engineering development of these systems should be carefully monitored though the program.

#### 8.6 References

- 8-1 EPRI, AC/DC Power Converter for Batteries and Fuel Cells" EPRI EM-1280, Dec. 1979
- 8-2 Westinghouse Internal Report 1981

- 8-3 EPRI, "Description of a Generic 11-MW Fuel Cell Power Plant for  
Utility Applications, EPRI EM-311, Sept 1983
- 8-4 Westinghouse, "Phosphoric Acid Fuel Cell 7.5 MWe DC Electric Power  
Plant Conceptual Design Report



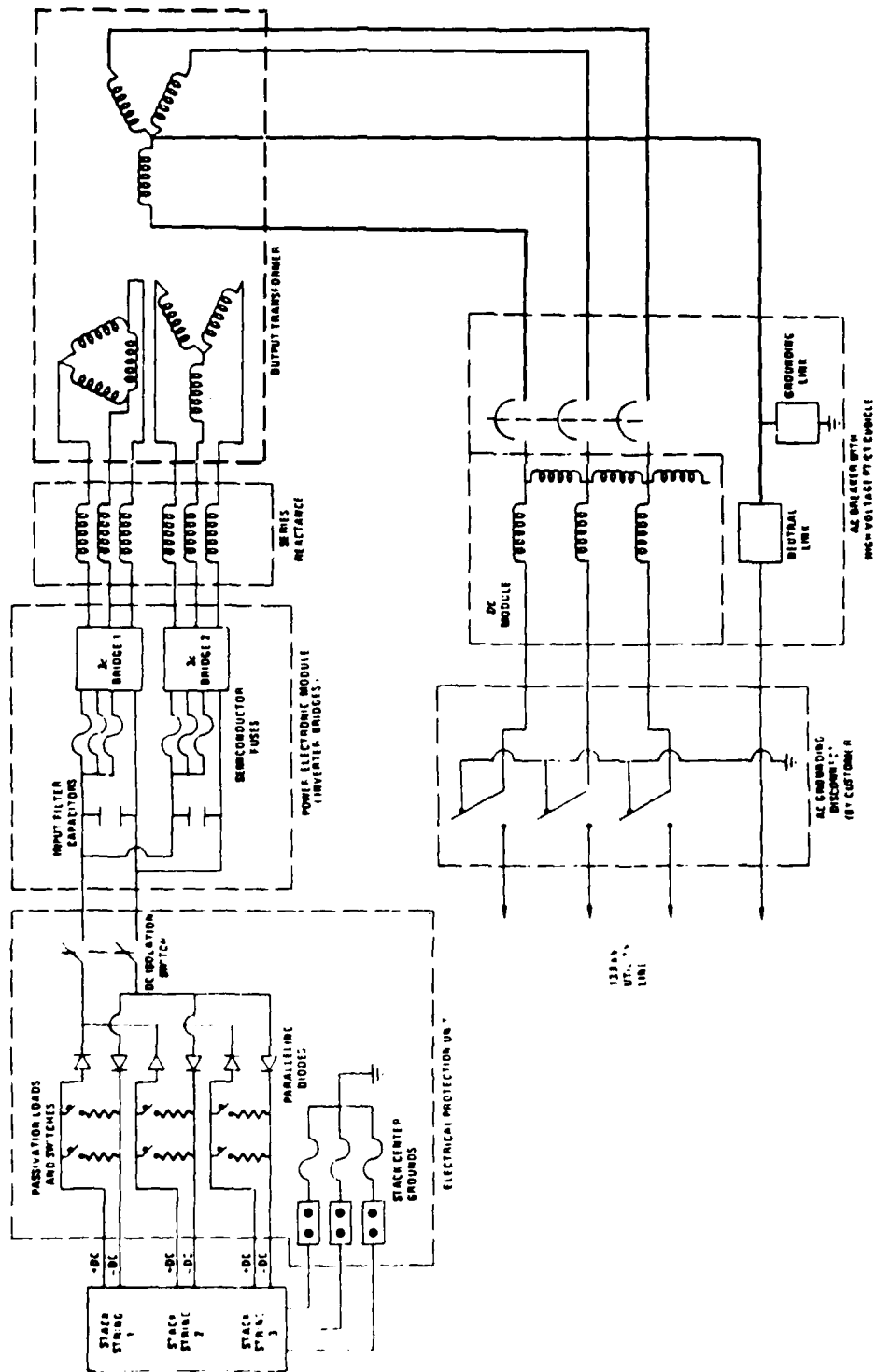


FIGURE 8 -1 UTC POWER CONDITIONER SCHEMATIC

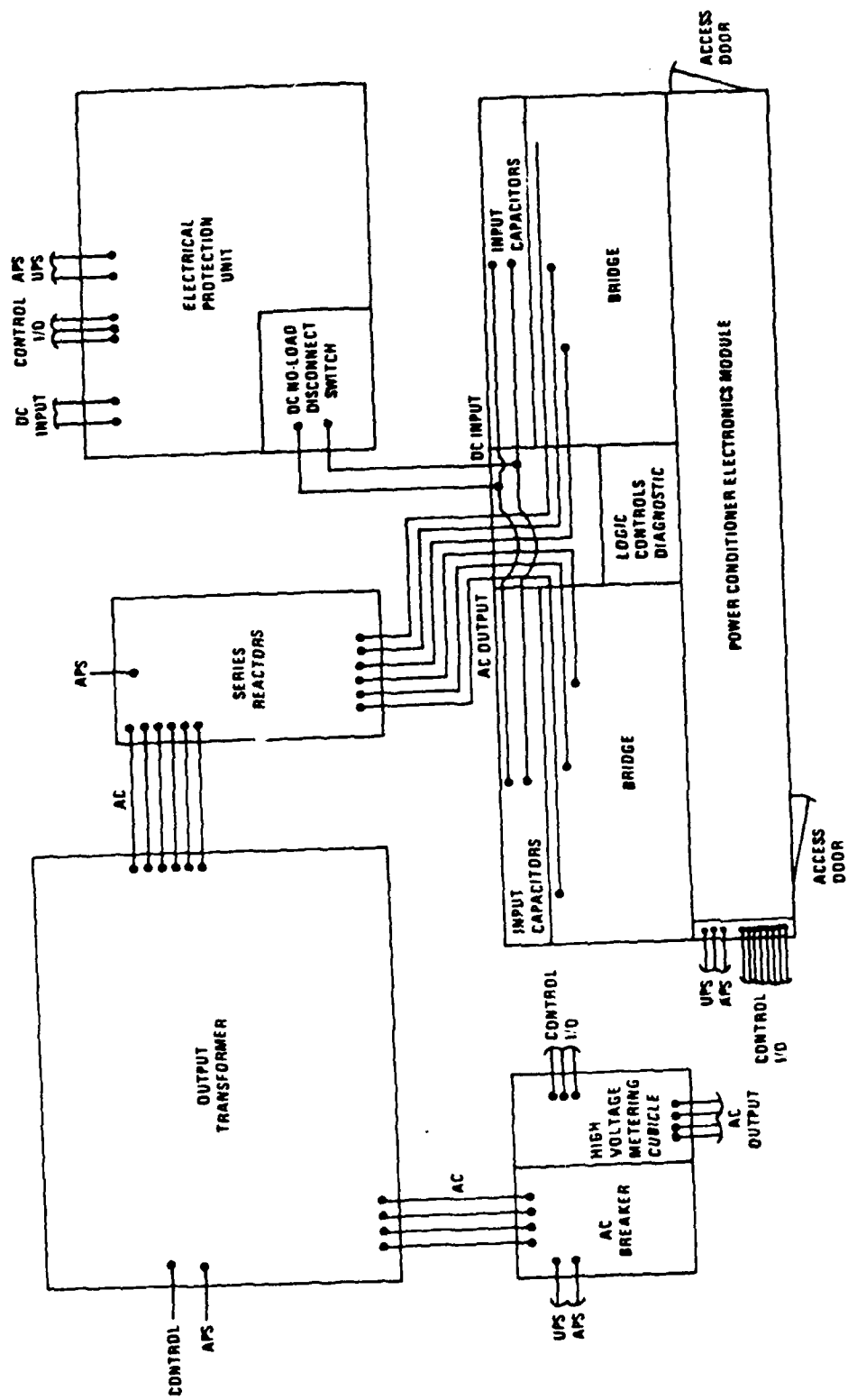


FIGURE 8-2 UTC POWER CONDITIONER GENERAL ARRANGEMENT

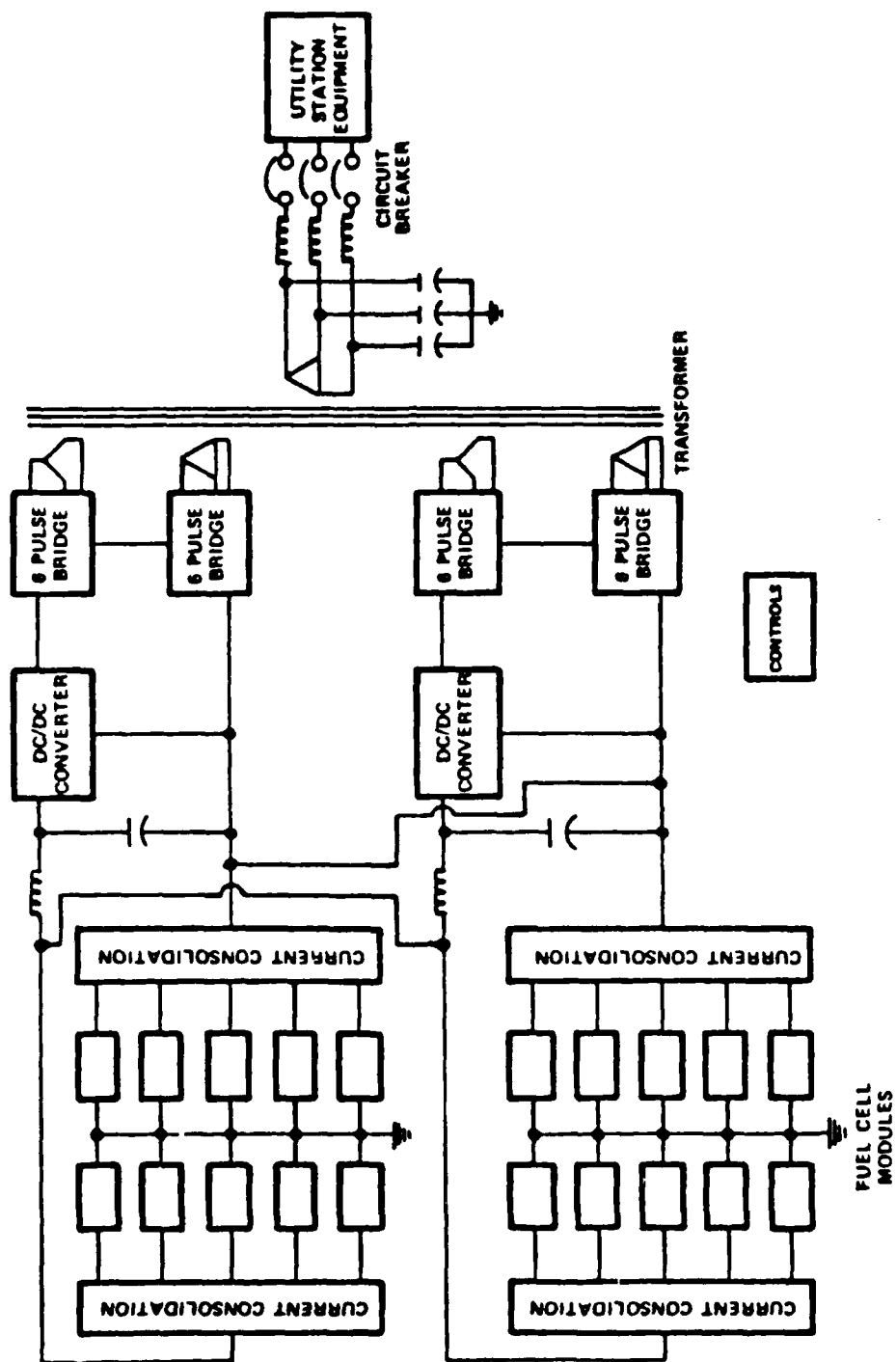


FIGURE 8 - 3 WESTINGHOUSE POWER CONDITIONER SCHEMATIC

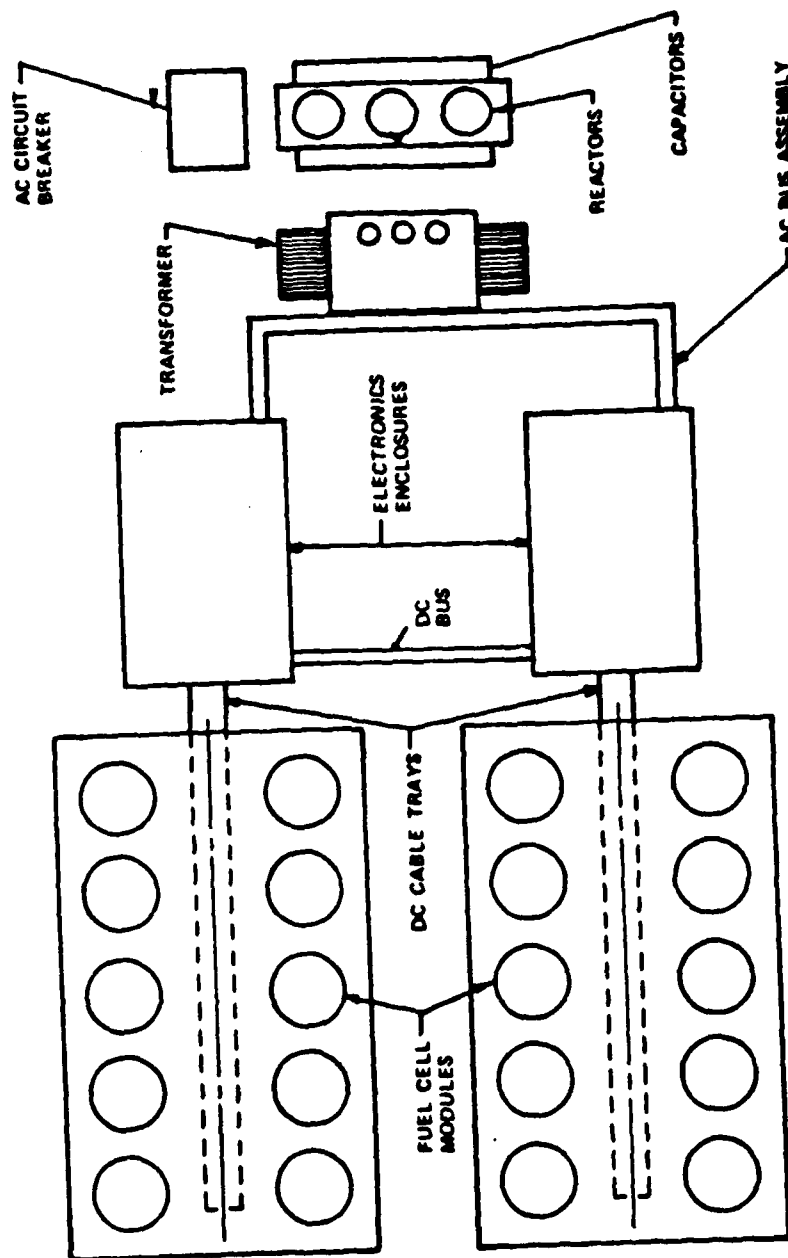


FIGURE 8 - 4 WESTINGHOUSE POWER CONDITIONER TYPICAL ARRANGEMENT

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